The Thesis committee for Michael Joseph O'Donnell

Certifies that this is the approved version of the following thesis:

Barriers to a Biofuels Transition in the U.S. Liquid Fuels Sector

Approved by
Supervising Committee:

Supervisor: Michael E. Webber

David T. Allen

Barriers to a Biofuels Transition in the U.S. Liquid Fuels Sector

by

Michael Joseph O'Donnell, B.S.M.E.

Thesis

Presented to the Faculty of the Graduate School of

The University of Texas at Austin

in Partial Fulfillment

of the Requirements

for the Degree of

Master of Science in Engineering

The University of Texas at Austin

December 2009

Dedication

This thesis is dedicated to my loving and accommodating wife, Sara,
and my precious sons, Owen and Aidan.

Acknowledgements

The completion of this thesis would not have been possible without the advisory support of Dr. Michael E. Webber, Dr. David T. Allen, and Cindy Murphy.

December 2009

Abstract

Barriers to a Biofuels Transition in the U.S. Liquid Fuels Sector

Michael Joseph O'Donnell, M.S.E.

The University of Texas at Austin, 2009

Supervisor: Michael E. Webber

Demand for liquid fuels (i.e., petroleum products) has burdened the U.S. with major challenges, including national security and economic concerns stemming from rising petroleum imports; impacts of global climate change from rising emissions of CO2; and continued public health concerns from criteria and hazardous (i.e., toxic) air pollutants. Over the last decade or so, biofuels have been touted as a supply-side solution to several of these problems. Biofuels can be produced from domestic biomass feedstocks (e.g., corn, soybeans), they have the potential to reduce GHG emissions when compared to petroleum products on a lifecycle basis, and some biofuels have been shown to reduce criteria air pollutants. Today, there are numerous policy incentives—existing and proposed—aimed at supporting the biofuels industry in the U.S. However, the Renewable Fuel Standard (RFS) Program stands as perhaps the most significant mandate imposed to date to promote the use of biofuels. Overall, the RFS stands as the key driver

in a transition to biofuels in the near term. By mandating annual consumption of biofuels, increasing to 36 bgy by 2022, the program has the potential to significantly alter the state of the U.S. liquid fuels sector.

Fuel transitions in the transportation sector are the focus of this thesis. More specifically, the increasing consumption of biofuels in the transportation sector, as mandated by the RFS, is examined. With a well-developed, efficient, and expensive, petroleum-based infrastructure in place, many barriers must be overcome for biofuels to play a significant role in the transportation sector. Identifying and understanding the barriers to a biofuels transition is the objective of this thesis.

Although fuel transitions may seem daunting and unfamiliar, the U.S. transportation sector has undergone numerous transitions in the past. Chapter 2 reviews major fuel transitions that have occurred in the U.S. liquid fuels sector over the last half century, including the phasing out of lead additives in gasoline, the transition from MTBE to ethanol as the predominant oxygenate additive in gasoline, and the recent introduction of ULSD. These historical transitions represent the uncertainty and diversity of fuel transition pathways, and illustrate the range of impacts that can occur across the fuel supply chain infrastructure. Many pertinent lessons can be derived from these historical transitions and used to identify and assess barriers facing the adoption of alternative fuels (i.e., biofuels) and to understand how such a transition might unfold.

Computer models can also help to explore the implications of fuel transitions. In order to better understand the barriers associated with fuel transitions, and to identify options for overcoming these barriers, many recent research efforts have used sophisticated modeling techniques to analyze energy transitions. Chapter 3 reviews a number of these recent modeling efforts with a focus on understanding how these methodologies have been applied, or may be adapted, to analyzing a transition to biofuels. Four general categories of models are reviewed: system dynamics, complex adaptive systems, infrastructure optimization, and economic models.

In chapter 4, scenarios created from a high-level model of the liquid fuels sector (the Liquid Fuels Transition model) are presented to explore potential pathways and barriers to a biofuels transition. The scenarios illustrate different pathways to meeting the requirements of the RFS mandate, and differ based on the overall demand of liquid fuels, how the biofuels mandate is met (i.e., the mix of biofuels), and the status of the ethanol blend limit in the motor gasoline sector. The scenarios are used to evaluate the infrastructure implications associated with a biofuels transition, and illustrate the uncertainty that exists in assessing such a transition.

Table of Contents

Chapter 1. Introduction

1.1 Overview of the U.S. Liquid Fuels Sector

Petroleum has served as the primary energy source consumed in the U.S. since the middle of the last century. Over the last decade, primary energy consumption has fluctuated around 100 quadrillion Btu (quads). Petroleum's share of primary energy consumption has stood at approximately 40% since the late 1980s, falling slightly to 37.4%, or 37.1 quad, in 2008 (see Figure 1-1) [1].

Crude oil is the primary feedstock used to produce liquid fuels in the U.S. Aside from petroleum products, the liquid fuels sector is comprised of natural gas liquids, ethanol, biodiesel, and other non-crude-derived fuels (e.g., liquids from gas, coal, and biomass). In 2008, crude oil-derived fuels made up 95% of all liquid fuels consumption (by volume) [2]. Presently, the liquid fuels sector can essentially be viewed as the petroleum products sector. Over the last half century, the majority of the sector has been comprised of motor gasoline and distillate fuel oil (DFO) products. Figure 1-2 shows the breakdown of petroleum products supply in 1958 and 2008. Motor gasoline and DFO products have slightly increased their share of the petroleum products supply from 60% to 66% during this time period [3].

The transportation sector consumes the majority of petroleum products in the U.S (other sectors include the residential, commercial, industrial, and electricity supply). In 2008, approximately 70% of the petroleum products supply was required to power transportation activities (see Figure 1-3) [3, 4]. Figure 1-4 shows that petroleum's share of the transportation sector has increased from 77% to 94.3% from 1949 to 2008, peaking at 97.2% in 1978. In 2008, the sector consumed 26.3 quads of petroleum, encompassing over one quarter of primary energy consumption (100 quads) [5].

Of the petroleum products consumed in the transportation sector in 2008, motor gasoline made up 64.3% of this demand. Although motor gasoline's share of the market has slowly declined over the last three decades as demand for distillate has increased (see

Figure 1-5), motor gasoline still stands as the predominant fuel demanded by the U.S. transportation sector. Distillate products supplied 21% of this demand in 2008 [4].

The nation's demand for petroleum products is increasingly being supplied by imports. Figure 1-6 shows that the majority of the petroleum products supply is comprised of imports. Imports grew from 10% to 66% between 1949 and 2008, respectively [6].

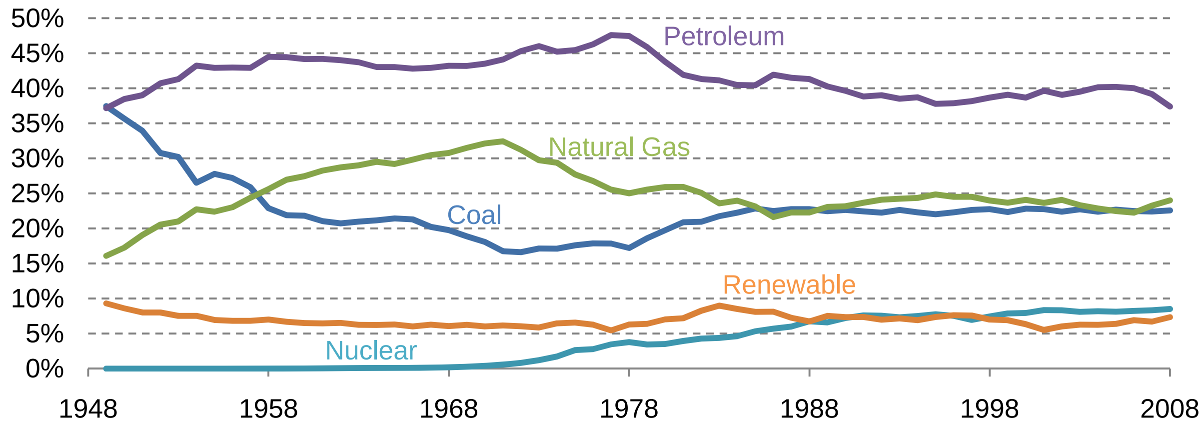


Figure 1-1. Primary Energy Consumption by Source, 1949-2008. The shares of primary energy consumption by source have been steady since the late 1980s. Petroleum has served as the number one primary energy source since the middle of the last century, making up 37.4% of consumption in 2008 [1]. Primary energy consumption has fluctuated around 100 quads over the last decade.

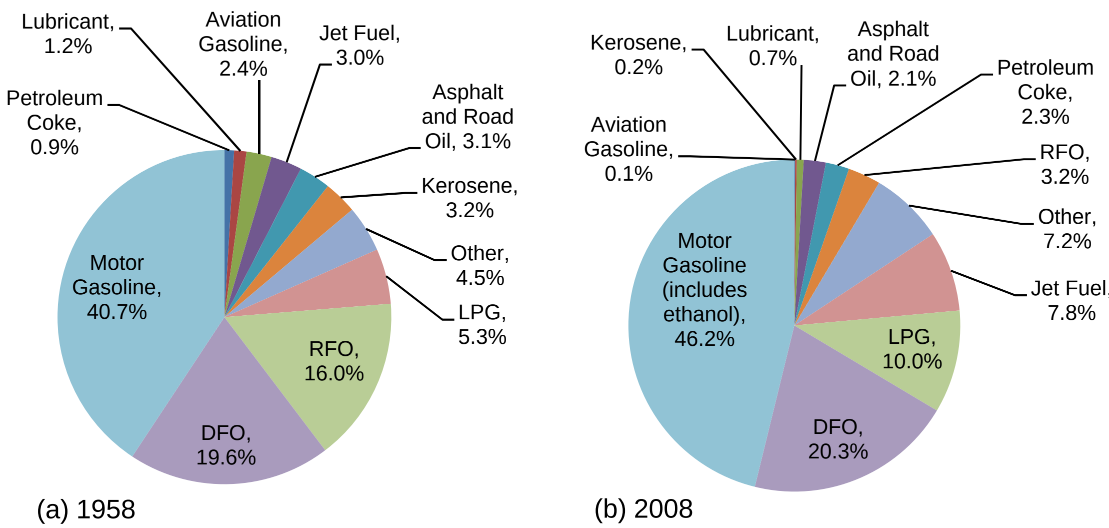


Figure 1-2. Petroleum Product Supplied by Type, 1958 and 2008. Motor gasoline and DFO comprised 60% and 66% of all petroleum (i.e., liquid fuels) products supplied in 1958 and 2008, respectively [3]. LPG is liquefied petroleum gases; RFO is residual fuel oil; DFO is distillate fuel oil.

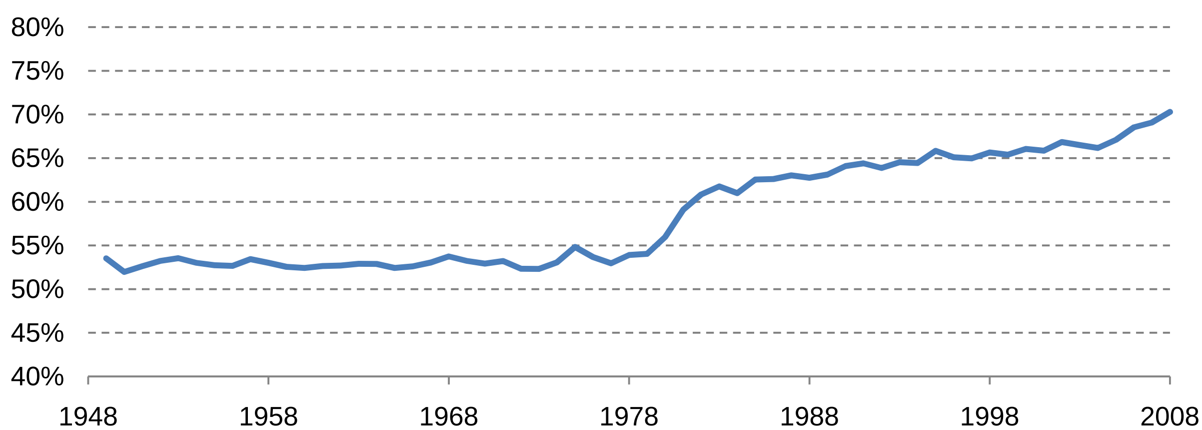


Figure 1-3. Percentage of Petroleum Consumed in the Transportation Sector, 1949-2008. The percentage of petroleum products supply (i.e., liquid fuels supply) consumed by transportation activities has steadily increased from just under 55% (1948-1978) to over 70% in 2008 [3, 4].

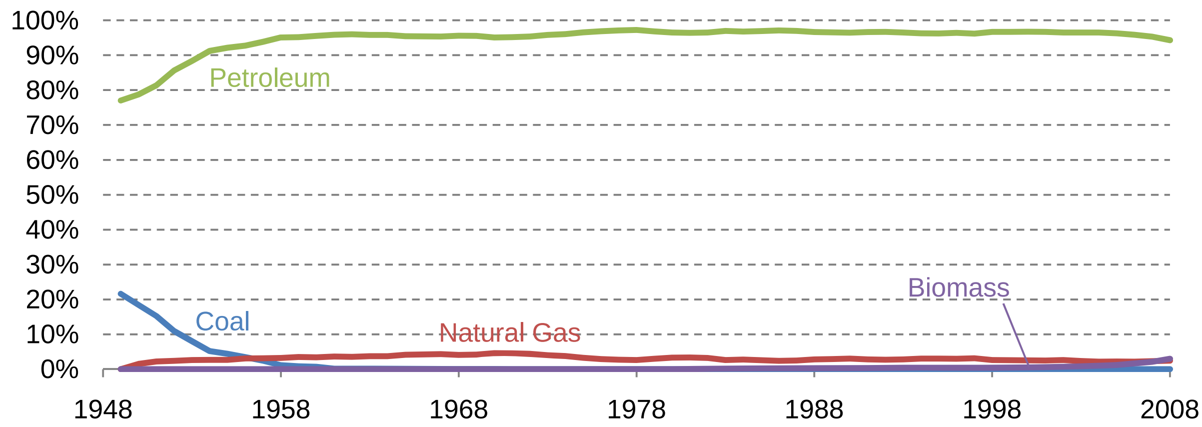


Figure 1-4. Estimated Share of Primary Energy Sources Consumed in the Transportation Sector, 1949-2008. Petroleum has dominated the supply of energy consumed in the transportation sector for the majority of the last century [5]. The reduction in coal consumption resulted from the transition from coal-steam-driven to diesel-powered locomotives that occurred in the middle of the last century.

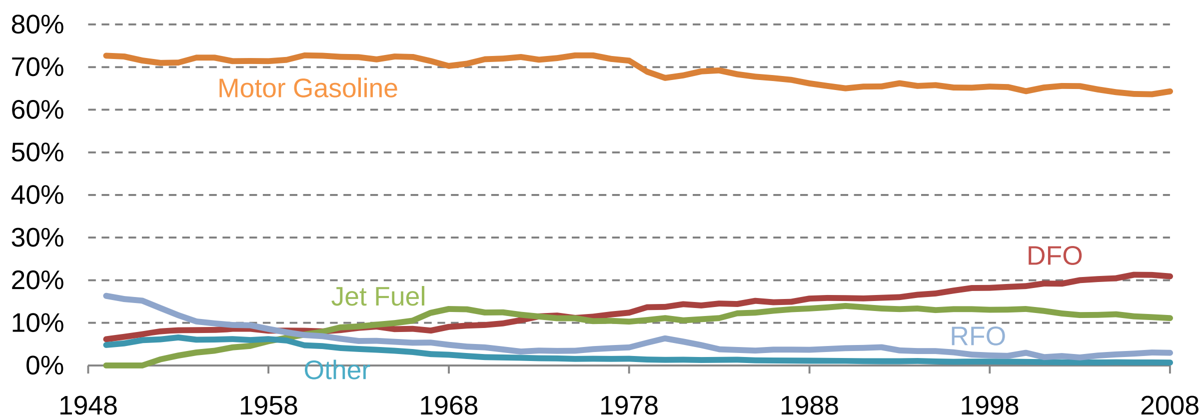


Figure 1-5. Estimated Shares of Petroleum Products Consumed in the Transportation Sector, 1949-2008. Motor Gasoline and DFO are the primary petroleum products used to power transportation activities in the U.S. [4].

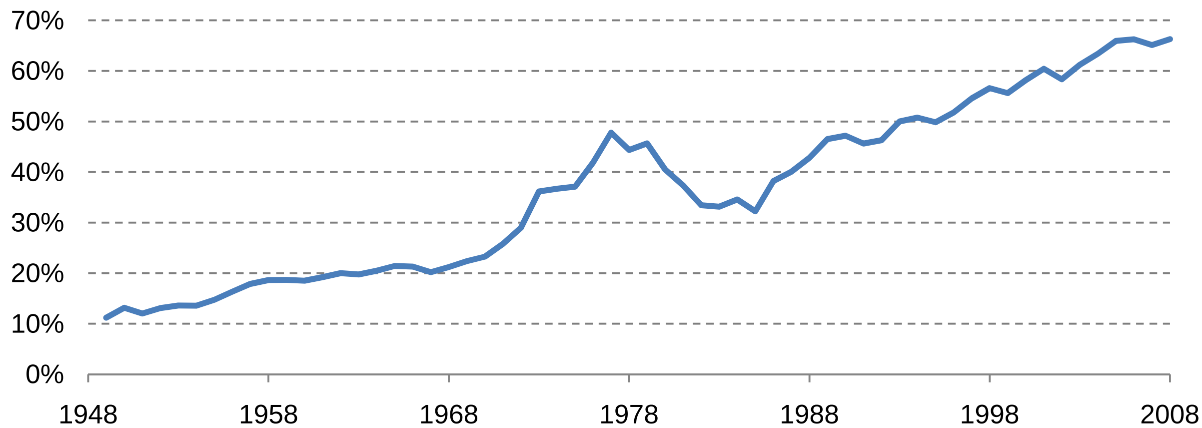


Figure 1-6. Percentage of Petroleum Products Supplied by Imports, 1949-2008. From 1949 to 2008, imports ballooned from 10% to 66% of the U.S. petroleum products supply [6].

A significant portion of CO_2 emissions from U.S. energy consumption results from the combustion of liquid fuels. In 2007, primary energy consumption in all sectors produced 5,990 million metric tons of CO_2 (MMT CO_2) emissions. As the primary energy source, petroleum consumption produced the most emissions of all energy sources (e.g., natural gas, coal, etc), yielding 2,579 MMT CO_2, or 43% of emissions from primary energy consumption (see Figure 1-7). In terms of end-use consumption, the transportation sector was responsible for 33.5% of total emissions from primary energy consumption, or 2,009 MMT CO_2 [7]

Motor gasoline consumption in all sectors produced 1,208 MMT CO_2, with 97.7% of these emissions, or 1,180 MMT CO_2, attributable to gasoline consumption in the transportation sector. Motor gasoline consumption in the transportation sector produced 20% of CO_2 emissions from primary energy consumption in all sectors. Motor gasoline consumption in the transportation sector stands behind only coal consumption in the electric power sector as the number two producer of CO_2 emissions resulting from primary energy consumption (by energy source and end-use sector). DFO consumption in all sectors produced 652 MMT CO_2, with 72.4%, or 472 MMT CO_2, attributable to distillate consumption in the transportation sector. DFO consumption in the transportation sector amounted to nearly 8% of CO_2 emissions from primary energy consumption in all sectors (again, by energy source and end-use sector).

Motor gasoline and DFO consumption were responsible for 46.8% and 25.3% of CO_2 emissions produced from liquid fuels (i.e., petroleum products) consumption in all sectors, respectively (see Figure 1-8) [7]. Note that the share of CO_2 emissions amongst petroleum products is nearly analogous to the share of petroleum products consumption by volume (comparing Figures 1-2(b) and 1-8).

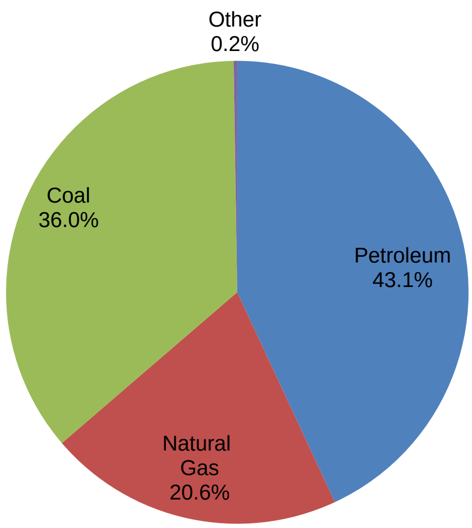


Figure 1-7. Share of CO_2 emissions from energy consumption by energy source, 2007. Petroleum consumption resulted in 43% of emissions from primary energy consumption in the U.S. [7].

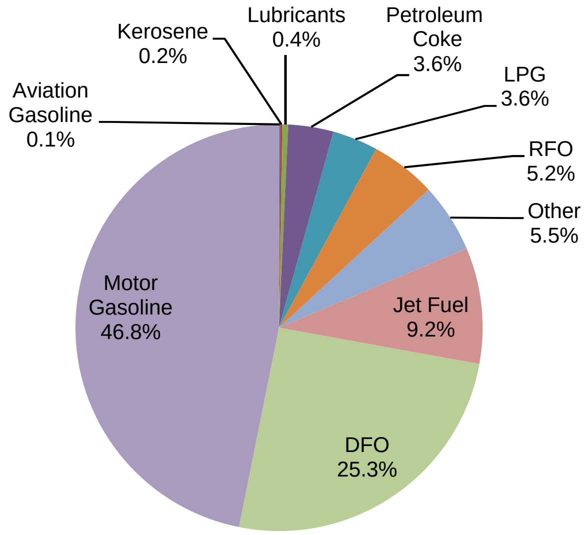


Figure 1-8. Share of CO_2 emissions from petroleum consumption by petroleum product type, 2007. Motor gasoline and DFO consumption produced 72.1% of CO_2 emissions from petroleum products consumption [7].

1.2 Motivation for Biofuels

Demand for liquid fuels (i.e., petroleum products) has burdened the U.S. with major challenges. Rising imports have grown from resource limitations (i.e., depletion of U.S. crude oil supplies). Relying so heavily on imports has exposed the nation to national security (e.g., volatile international relations with oil producing nations) and economic concerns (e.g., unstable oil prices). Anthropogenic emissions of CO_2—a greenhouse gas (GHG)—are contributing to global climate change. The combustion of liquid fuels also produces emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM), volatile organic compounds (VOCs), various toxic compounds, and the formation of smog. Despite progress in controlling such emissions over the last several decades, these non-CO_2 emissions continue to contribute to public health concerns.

Addressing these problems will ultimately require the application of many demand- and supply-side solutions in the liquid fuels sector. With the majority of liquid fuels consumption occurring in the transportation sector, the challenge to develop alternative sources that reduce petroleum consumption and minimize or eliminate GHG emissions is formidable. Controlling GHG emissions (e.g., CO_2 emissions) from millions of mobile sources in the transportation sector might prove to be more challenging than controlling emissions from hundreds or thousands of stationary, fossil-fuel burning, thermoelectric power plants.

Over the last decade or so, biofuels have been touted as a supply-side solution to several of these problems. Biofuels can be produced from domestic biomass feedstocks (e.g., corn, soybeans), rather than being imported. They have the potential to reduce GHG emissions when compared to petroleum products on a lifecycle basis. Additionally, some biofuels have been shown to reduce criteria air pollutants (e.g., biodiesel substantially reduces CO and PM emissions when used in diesel-powered equipment, but has been shown to increase NOx emissions [8]).

Presently, the U.S. biofuels industry is a fledgling, but rapidly growing, industry. The industry has been supported through numerous government policies aimed at lessening the burdens derived from the nation's petroleum consumption. In the next section, the U.S. biofuels industry is discussed, with a focus on ethanol and biodiesel. Policies that have helped to develop, and will continue to support, the industry are also reviewed.

1.3 Biofuels Industry and Policies

The Energy Policy Act (EPAct) of 1992 defines the following fuels as alternative transportation fuels [9]:

Biodiesel	Biogas
Electricity	Biomass to Liquids (BTL)
Ethanol	Coal to Liquids (CTL)
Hydrogen	Fischer-Tropsch (FT) Diesel
Methanol	Gas to Liquids (GTL)
Natural Gas	Hydrogenation-Derived Renewable Diesel (HDRD)
Propane	P-Series
	Biobutanol

According to the U.S. Department of Energy (USDOE), the fuels listed in the left column are currently, or have been, commercially available in the transportation sector. Those listed in the right column have been researched and several are currently under development [10]. The focus of this thesis is on the use of biofuels in the liquid fuels sector; therefore, only biofuels from the above list are considered further, i.e., biodiesel, ethanol, BTL, FT diesel, renewable diesel (HDRD), and biobutanol. Ethanol and biodiesel have emerged as leaders in terms of market penetration; these biofuels are reviewed in further detail below. Despite the prominence of ethanol and biodiesel, several other biofuels have the potential to supply the liquid fuels sector in the near future.

For example, biobutanol, an alcohol fuel that can be derived from corn, wheat, sugar beets, and sugar cane, is being pursued in a joint partnership between BP and DuPont. The companies promote the fuel as a better alternative to ethanol with the capability of blending with gasoline at higher levels in existing engines, and the ability to transport the fuel via existing pipeline infrastructure [11]. Biobutanol's role in the liquid fuels sector is explored further in chapter 4.

ConocoPhillips and Tyson formed a partnership to produce renewable diesel—a marketing term used to represent HDRD. In a 2008 pilot program, ConocoPhillips converted waste animal fat, supplied by Tyson, into a fuel that is chemically similar to ultra-low sulfur diesel produced from crude oil. Unlike biodiesel, this fuel has the advantage of being fully compatible with existing pipelines and diesel engine technologies. Due to "unfavorable economics", ConocoPhillips suspended the pilot project in late 2008. The company hopes to resume production when economic conditions become more favorable [12].

1.3.1 Biofuels industry

The biofuels industry in the U.S. is comprised primarily of ethanol and biodiesel production. Despite recent research and support for alternative, advanced biofuels (e.g., cellulosic ethanol, renewable diesel), the so-called “first-generation” biofuels serve as the only commercial scale biofuels presently produced and consumed in the nation.

1.3.1.1 Ethanol

Ethanol—an alcohol fuel derived from various biomass feedstocks (e.g., corn, sugar cane) and used as a gasoline additive and substitute—is not a new fuel. In 1908, Henry Ford produced the Model T as a flex-fuel vehicle, capable of running on ethanol, gasoline, or blends of the two fuels. Ford referred to ethanol as the “fuel of the future.” During World War I, fuel shortages increased demand for ethanol to 50-60 million gallons per year (mgy). During the 1930’s, gasohol, a blend of gasoline and 6-12% ethanol, was offered throughout the Midwest. However, following World War II, ethanol’s use as a commercial fuel dwindled, and the fuel was more or less unavailable throughout the nation. Following the oil embargos of the 1970s, support for ethanol once again grew. Several legislative actions were taken by the federal government, most notably, the Energy Tax Act of 1978, which defined gasohol as a blend of gasoline with a minimum of 10% alcohol (e.g., ethanol) by volume, excluding alcohols derived from fossil fuels. The Act also provided a $0.40 per gallon subsidy for each gallon of ethanol used in gasohol blends [13].

The marketing of commercial alcohol-blended fuels was initiated in 1979 by the Amoco Oil Company. In the following years, the federal government implemented numerous programs to support the fledgling ethanol industry, and even increased the ethanol subsidy to $0.60 per gallon in 1984. Despite these efforts, the industry struggled, with many producers going out of business the following year. Ethanol saw its next resurrection as a means for controlling air emissions,[1] being used as an additive in gasoline to reduce CO emissions during the winter months in states that implemented oxygenated fuels programs [13].

The historical consumption of ethanol fuel in the U.S. since 1981 is shown in Figure 1-9. In 1981, the first year that the Energy Information Administration (EIA) provided an estimate of ethanol consumption, only 5 mgy of ethanol were consumed. Interestingly, estimates indicate that over 10 times this amount of ethanol were consumed annually during World War I [13]. A major boost to the ethanol industry, which aided in the rapid growth of ethanol consumption since 2005, was the passage of the EPAct of 2005. This Act implemented the Renewable Fuels Standard (RFS) program, which mandates minimum volumes of biofuels consumption. In 2008, when the program mandated the consumption of 9 bgy of renewable fuels, the domestic ethanol industry produced over 9.2 billion gallons of fuel ethanol. When combined with imports, nearly 9.6 billion gallons of fuel ethanol were consumed, mainly in the form of low-level blends with gasoline (e.g., E10) [13-15]. Further details of the RFS, and other alternative fuel policies, are discussed below in section 1.3.2.

A map of existing facilities (both operating and idled) and those under construction is provided in Figure 1-11. With corn being the most common ethanol feedstock in the U.S., the highest density of ethanol facilities are located in the "corn belt", i.e., the region of the Midwest and Great Plains that produces the majority of the corn crop in the U.S.

As of August 4, 2009, 201 ethanol refineries provide a nameplate production capacity of 13.06 billion gallons per year (bgy), with 11.53 bgy classified as operating refineries, leaving 1.53 bgy of nameplate capacity idled. An additional 1.47 bgy of capacity is under construction (new or expanding refineries). The capacity provided by all refineries that are operating, idled, and under construction sums to 14.53 bgy [16]. This capacity nearly fulfills the 15 bgy limit on conventional biofuels production mandated under the RFS program in 2015.

---

[1] This use of ethanol is discussed further in chapter 2. The use of ethanol as an oxygenate in Reformulated Gasoline (RFG) is also discussed, in detail, in chapter 2.

The growth of the ethanol industry from the 1980s to present day is discussed further in chapter 2.

1.3.1.2 Biodiesel

Although ethanol stands as the predominant biofuel consumed in the nation, the biodiesel industry has played an important role in the growth of the renewable fuels industry. Biodiesel is a distillate additive and substitute derived from triglycerides (e.g., rendered animal fats, vegetable oils). The biofuel is produced through the transesterification process, a reaction between triglycerides and an alcohol (e.g. methanol) in the presence of a catalyst. The resulting fuel is a mono-alkyl ester of long chain fatty acids (e.g., fatty-acid-methyl ester, or FAME). The official definition of biodiesel, which is consistent with federal and state laws, is as follows [17]:

> Biodiesel is defined as mono-alkyl esters of long chain fatty acids derived from vegetable oils or animal fats which conform to ASTM D6751 specifications for use in diesel engines. Biodiesel refers to the pure fuel before blending with diesel fuel. Biodiesel blends are denoted as, "BXX" with "XX" representing the percentage of biodiesel contained in the blend (ie: B20 is 20% biodiesel, 80% petroleum diesel).

Figure 1-10 shows the historical consumption of biodiesel since 2001. Growth in domestic consumption slowed in 2007 and actually dropped in 2008. However, domestic production actually increased to nearly 0.5 and 0.7 bgy in 2007 and 2008, respectively [18]. This mismatch between domestic consumption and production was due to a rapid increase in biodiesel exports to the European Union (EU). A map of existing biodiesel production facilities is provided in Figure 1-12.[2]

The growth of the biofuels industry was aided by government incentives. An overview of key legislation and policies, primarily from the federal level, follows.

[2] Unlike the ethanol map in Figure 1-11, TransAtlas does not include data on biodiesel facilities that are idled or under construction.

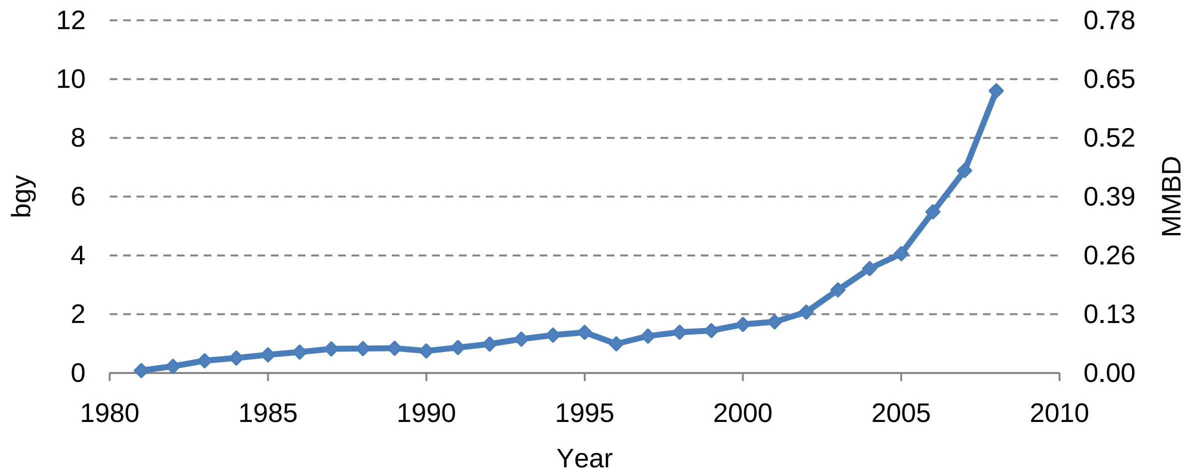


Figure 1-9. U.S. ethanol consumption has increased rapidly since the phase-out of MTBE and inception of the RFS program [15]. Ethanol consumption is shown in billion gallons per year (bgy) and million barrels per day (MMBD).

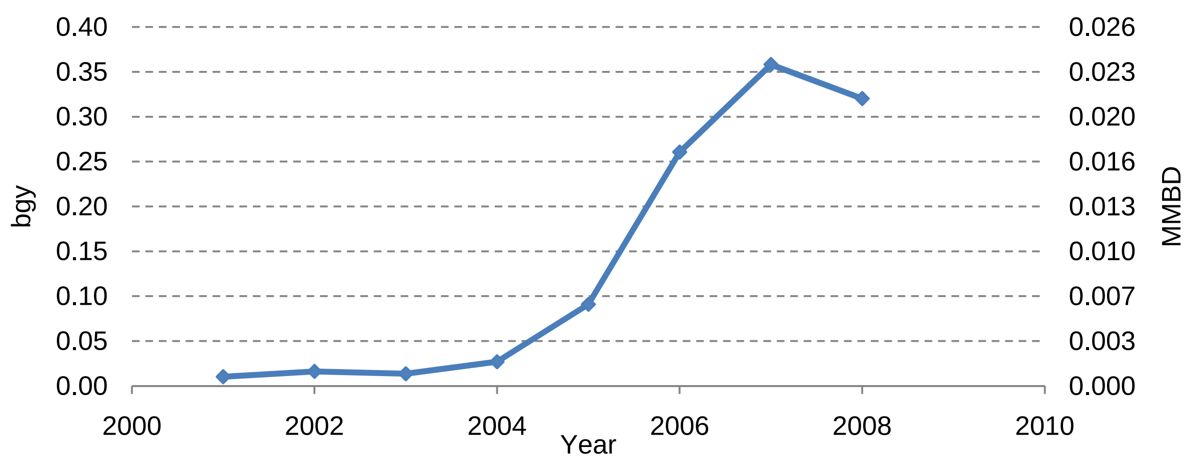


Figure 1-10. U.S. biodiesel consumption increased rapidly following the inception of the RFS program [18]. Biodiesel consumption is shown in billion gallons per year (bgy) and million barrels per day (MMBD).

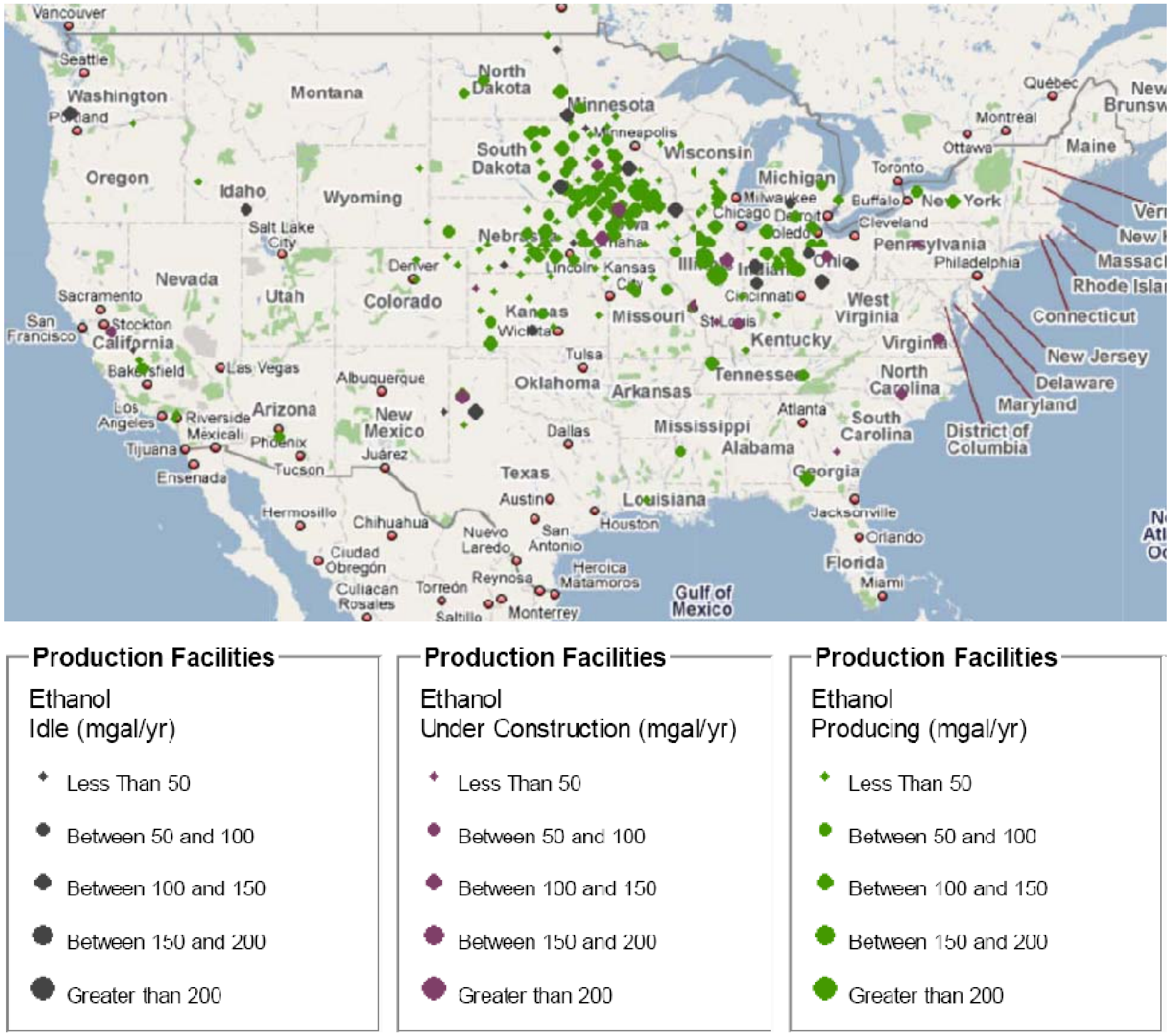


Figure 1-11. Ethanol production facilities in the U.S. are heavily concentrated in the "corn belt".[3] Current market conditions, and the general market downturn, have forced many facilities to idle operations over the last year (indicated by dark grey circles) [19].

[3] This figure was developed using TransAtlas, an interactive map developed by the National Renewable Energy Laboratory that uses a Google Maps interface to display various alternative fuel infrastructure data. See http://rpm.nrel.gov/transatlas/.

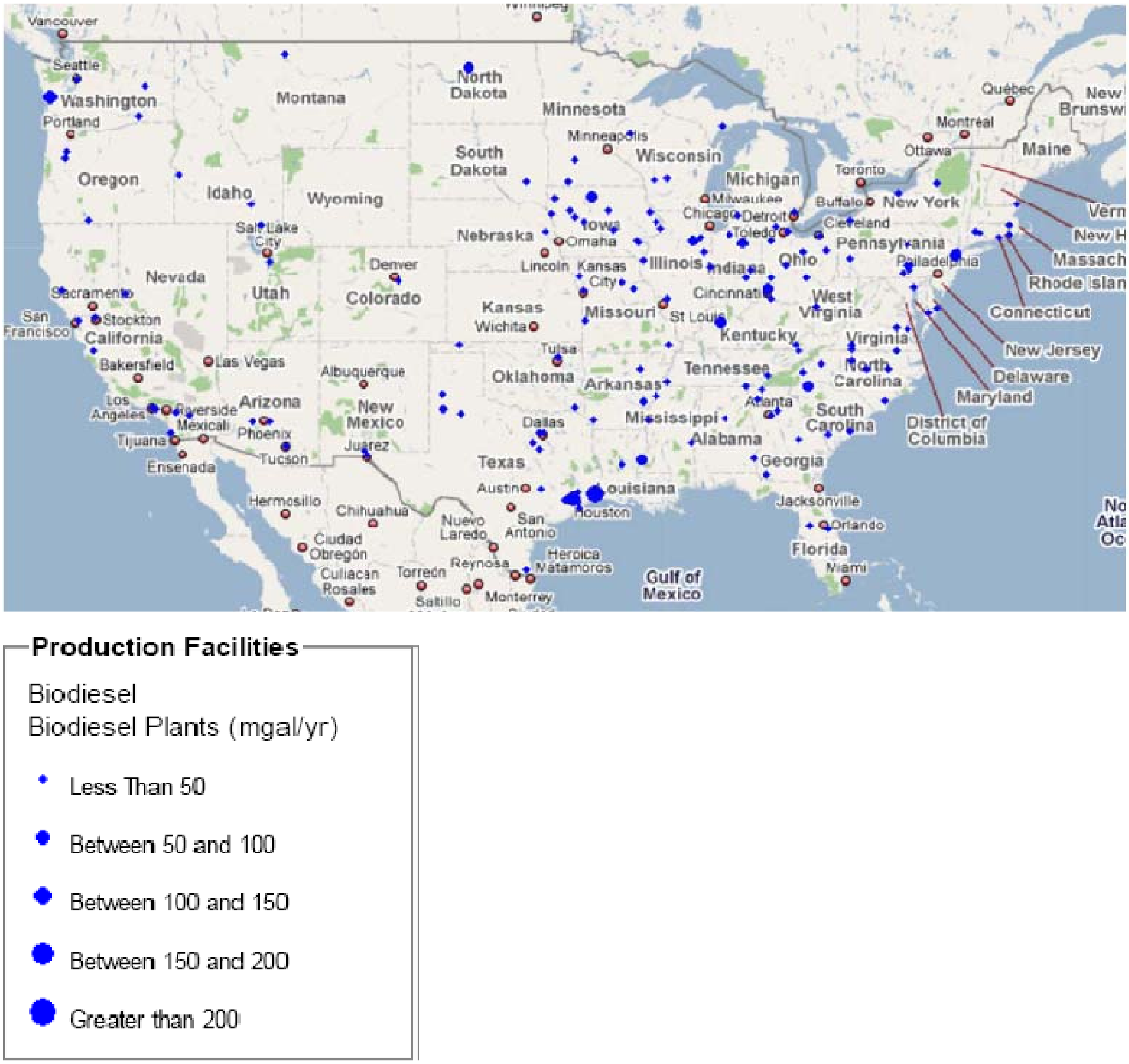


Figure 1-12. Biodiesel production facilities in the U.S. are more widely dispersed compared to the ethanol industry [19]. Feedstocks used to make biodiesel are quite diversified (e.g., vegetable oils, yellow grease, tallow, etc), allowing for greater geographic dispersion. Despite this diversity, the biodiesel feedstock supply lags significantly behind the massive corn yields that feed the ethanol industry.

1.3.2 Biofuel policies

Today, there are numerous policy incentives—existing and proposed—aimed at supporting the biofuels industry in the U.S. According to the Renewable Fuels Association (RFA), an ethanol industry-advocacy group, there were 57 ethanol-related bills introduced in the 110th Congress, and 31 introduced in the 111th Congress [20]. An exhaustive review of policies related to alternative fuels, or even biofuels alone, would be a daunting task. Therefore, various categories of these policies will be discussed with attention focused on key legislation and programs that currently support the biofuels industry.

Policies that promote the development of alternative fuels come in the form of tax incentives, tariffs, direct assistance, and mandates. At the federal level, each of the following agencies and departments administer programs related to alternative fuels:

- Environmental Protection Agency (EPA)
- Department of Agriculture (USDA)
- Department of Energy (USDOE)
- Department of Transportation (USDOT)
- Internal Revenue Service (IRS)
- Customs and Border Protection

As explained previously, alcohol fuels (e.g., ethanol) received their first boost from the federal government in 1978 when gasohol (10% ethanol blended with gasoline) was given a subsidy of $0.40 per gallon. This incentive has been altered and extended over time and now stands amongst several incentives administered by the IRS to support the development, production, and consumption of alternative fuels, e.g. [21, 22]:

- Alternative Fuel Tax Credits (e.g., Excise, Infrastructure, Mixture Excise, Biodiesel Income and Mixture Excise, Cellulosic Biofuel Producer)
- Motor Vehicle Credits (Fuel Cell, Hybrid Electric, Plug-In Electric)

- Biodiesel and Ethanol Tax Credits (e.g. Volumetric Ethanol Excise Tax Credit, i.e., VEETC)
- Small Agri-Biodiesel and Ethanol Producer Credits

The Biodiesel and Ethanol Tax Credits, otherwise known as the "blender's credits," have helped to stimulate growth in the biofuels industry over the last decade. These credits were established by the American Jobs Creation Act of 2004 and extended by the EPAct of 2005. The ethanol tax credit pays $0.51 per gallon of pure ethanol; this equates to 5.1 cents per gallon for E10, a blend of 10% ethanol found at many gas stations across the nation. The biodiesel tax credit pays $1.00 per gallon of biodiesel; this equates to 20 cents per gallon for B20, a blend of 20% biodiesel commonly used in school buses nationwide. The biodiesel tax credit only pays $0.50 per gallon when the feedstock is recycled cooking grease. Interestingly, the tax credit is granted to the fuel blender, not the biofuel producer.

The Small Producer Credits pay out $0.10 per gallon of fuel up to 30 million gallons for ethanol and up to 15 million gallons for biodiesel. Producers that make less than 60 million gallons of fuel per year are eligible. The Alternative Fuel Infrastructure Credit provides a tax credit of 30% of the cost of installing alternative refueling property, up to $30,000. Both the producer and infrastructure credits were established by the EPAct of 2005.

Only one tariff was identified as promoting the use of alternative fuels. The Import Duty for Fuel Ethanol was enacted by the Omnibus Reconciliation Act of 1980 and was most recently extended by the Tax Relief and Health Care Act of 2006. The law imposes a 2.5% ad valorem tariff and a most-favored-nation duty of $0.54 per gallon of ethanol on imports to the U.S. from most countries [9, 22]. This tariff protects the domestic corn ethanol industry against imports of Brazilian sugarcane ethanol.

A number of programs are in place to provide direct assistance to businesses, municipalities, and academic institutions in the form of grants and loans. The USDOE, USDA, and USDOT administer several programs that directly aid the development of alternative fuels, or indirectly through some other means (e.g. air quality improvement initiatives), e.g. [21]:

- Advanced Technology Vehicle (ATV) Manufacturing Incentives (USDOE)
- Biomass Research and Development Initiative (USDA)
- Biobased Products and Bioenergy Program (USDA)
- Renewable Energy Systems and Energy Efficiency Improvements Grant (USDA)
- Biobased Transportation Research Funding (USDOT)
- Clean Fuels Grant Program (USDOT)

The USDOE and EPA are responsible for administering a number of mandates and regulatory programs that promote the development of alternative fuels. These include, but are not limited to, Vehicle Acquisition and Fuel Use Requirements for Federal, State, and Local Government Fleets, and the Renewable Fuels Standard (RFS) Program [21, 22]. The EPA-administered RFS Program is perhaps the most significant mandate imposed to date to promote the use of biofuels. Brent Yacobucci, an Energy Policy Specialist with Congressional Research Service states this case clearly [22]:

> Arguably, the most significant federal programs for biofuels have been tax credits for the production or sale of ethanol and biodiesel. However, with the establishment of the [RFS] under [the EPAct of 2005], Congress has mandated biofuels use. In the long term, this mandate may prove even more significant than tax incentives in promoting the use of these fuels.

The requirements of the RFS, originally established under the EPAct of 2005, were boosted in December 2007 with the passing of the Energy Independence and Security Act (EISA) of 2007. The RFS now mandates 9.0 bgy of biofuels consumption in 2008 and ultimately requires 36 bgy in 2022 [14, 23, 24]. The annual biofuels consumption mandated by the RFS through 2022 is shown in Table 1-1.

Table 1-1. The RFS mandates annual consumption of biofuels through 2022 [14, 25].

Year	Cellulosic Biofuel	Biomass-Based Diesel	Total Advanced Biofuel	Total Renewable Fuel
2008	0	0	0	9.00
2009	0.00	0.50	0.60	11.10
2010	0.10	0.65	0.95	12.95
2011	0.25	0.80	1.35	13.95
2012	0.50	1.00	2.00	15.20
2013	1.00		2.75	16.55
2014	1.75		3.75	18.15
2015	3.00		5.50	20.50
2016	4.25		7.25	22.25
2017	5.50		9.00	24.00
2018	7.00		11.00	26.00
2019	8.50		13.00	28.00
2020	10.50		15.00	30.00
2021	13.50		18.00	33.00
2022	16.00		21.00	36.00

In Table 1-1, the difference between the total renewable fuel and total advanced biofuel mandates gives the volume of conventional biofuels allowed under the program. The conventional biofuel category is currently supplied by grain (i.e., corn) ethanol. The 15 bgy cap on conventional biofuels starting in 2015 was put in place to limit the amount of corn used to produce ethanol in future years. According to the EPA, cellulosic biofuel is expected to be produced as cellulosic ethanol. If this is the case, ethanol will supply nearly 31 bgy of the 36 bgy of the mandate in 2022. Since ethanol serves as an additive or substitute for gasoline, the motor gasoline sector is expected consume the majority of biofuels produced to meet the requirements of the RFS [25].

For a biofuel to qualify under the RFS, and contribute to annual volume mandates, GHG emission reduction thresholds must be met. GHG emissions are evaluated over the entire lifecycle of the fuel, including feedstock production (and land use change), fuel production, distribution, retail, and end use. The lifecycle GHG emissions are compared to the lifecycle emissions of a 2005 baseline petroleum fuel displaced by the biofuel, e.g., gasoline or diesel. The lifecycle GHG reduction thresholds, as a percent reduction from a 2005 baseline fuel, are listed in Table 1-2. The RFS also places limits on the types of feedstocks that can be used to produce biofuels under a given category. For example, the cellulosic biofuel category requires biofuels to be produced from cellulosic biomass, such as switchgrass, corn stover, wood wastes, etc.

Table 1-2. Biofuels must meet GHG reduction thresholds to qualify for the RFS. Lifecycle GHG reduction thresholds are based on a percent reduction from a 2005 baseline fuel. The threshold for conventional biofuels applies to biofuels production from facilities that initiated construction after December 19, 2007 [14, 25].

Biofuel Category	Lifecycle GHG Reduction Threshold
Conventional Biofuel	20%
Advanced Biofuel	50%
Biomass-Based Diesel	50%
Cellulosic Biofuel	60%

Any entity that produces transportation fuels (i.e., gasoline and diesel for highway and non-road use) for use in the U.S., including refiners, importers, and blenders, is expected to meet the RFS. These entities comply through the accumulation of credits, which are granted when biofuels are included in the products they deliver (in neat form or blended with conventional fuel products). Each year, the EPA calculates an annual percentage standard based on the RFS volumes and projected consumption of transportation fuels. This percentage standard is applied to the transportation fuels produced by each entity obligated under the RFS. For example, the percentage standard in 2009, as established by the EPA, is 10.21%. If an obligated entity produces 1 billion gallons of gasoline in 2009, it would be required to deliver 10.21 million gallons in the form of biofuels that comply with the requirements of the RFS (e.g., ethanol blended in gasoline). Exemptions are granted to small refiners and small refineries through 2010, and to gasoline producers located in Alaska, Hawaii, and noncontiguous U.S. territories indefinitely [14].

Other, more recently adopted, policy initiatives that could influence the adoption of biofuels in the liquid fuels sector include the California Low-Carbon-Fuel Standard (LCFS), Section 526 of the EISA of 2007, and the U.S. Air Force (USAF) domestic fuels policy.

The California LCFS, approved by the California Air Resources Board (CARB) on April 23, 2009, aims to reduce GHG emissions in California by reducing the carbon intensity of transportation fuels by an average of 10% by 2020 [26]. The carbon intensity (i.e., GHG emissions) of transportation fuels is measured across the full lifecycle of the fuel. The lifecycle approach, like the RFS program, ensures that emissions are accounted for in all segments of the fuel supply chain. However, this policy differs from the RFS in that it does not specify the type or volume of fuels to be consumed. The LCFS avoids "picking winners" by mandating an average reduction of lifecycle GHG emissions of transportation fuels, whether they be petroleum-based, biomass-based, or from various electricity sources used to power electric vehicles. Rather than mandating the use of biofuels, the LCFS establishes a GHG emissions reduction goal, allowing the market to find efficient solutions. An alternative fuel that provides greater, and more economical, reductions in lifecycle GHG emissions relative to a biofuel (e.g., corn-based ethanol) would be used first to meet the LCFS requirements. If such non-biofuel alternatives are developed, the LCFS could potentially result in a reduction in biofuels consumption, at least in the state of California.

Section 526 of the EISA of 2007 impacts the procurement of transportation fuels by federal agencies [24]:

> No Federal agency shall enter into a contract for procurement of an alternative or synthetic fuel, including a fuel produced from nonconventional petroleum sources, for any mobility-related use, other than for research or testing, unless the contract specifies that the lifecycle greenhouse gas emissions associated with the production and combustion of the fuel supplied under the contract must, on an ongoing basis, be less than or equal to such emissions from the equivalent conventional fuel produced from conventional petroleum sources.

Like the RFS program and LCFS, this policy requires alternative fuels to be evaluated based on lifecycle GHG emissions. In this case, the alternative fuel lifecycle emissions must be less than or equal to a baseline conventional fuel produced from conventional petroleum sources. Again, this policy could encourage or hinder the consumption of biofuels in the liquid fuels sector depending on how the lifecycle emissions of a given biofuel compare to those of the baseline conventional fuel. If the biofuel has greater lifecycle emissions, then a federal agency would be prohibited from procuring the fuel.

The USAF has adopted a domestic fuels goal, or policy, that will guide the military agency's fuel procurement decisions. The domestic fuels goal is to supply 50% of domestic fuel needs with 50/50 synthetic fuel blends by 2016, where the synthetic component of the blend is produced from a domestically-sourced feedstock (e.g., coal, biomass). The synthetic fuel component equates to approximately 400 mgy of domestically produced fuel for domestic consumption, based on the USAF's domestic fuel consumption of 1.6 bgy [27]. By comparing to the RFS in 2016, if the USAF were to procure synthetic blends derived from domestically produced biomass feedstocks, then approximately 2% of the RFS mandate would be satisfied by this USAF fuels goal. The USAF serves as an example of a federal agency that is subject to the requirements of Section 526. Therefore, the USAF is restrained in its domestic fuels procurement by the lifecycle emissions requirement of Section 526.

Additional fuel policies could be reviewed here, but these examples serve as a sampling of policies that could promote, or potentially slow, the adoption of biofuels and wider transition to biofuels in the U.S. liquid fuels sector. Overall, the RFS stands as the key driver in a transition to biofuels in the near term. By mandating annual consumption of biofuels, increasing to 36 bgy by 2022, the program has the potential to significantly alter the state of the liquid fuels sector.

1.4 Fuel Transitions

Technological transitions have been defined as major transformations in the way societal functions, such as transportation, are met. These transitions do not only deal with changes in technology, but with changes in practices, regulation, industrial networks, infrastructure, and culture. Geels identifies the following elements as being part of the "sociotechnical configuration" in transportation: culture and symbolic meaning; finance rules, insurance, interest rates; regulations and policies; road infrastructure, traffic systems; vehicle technologies; fuel infrastructure; markets and user practices; maintenance and distribution networks; industry structure [28]. A technological transition in the transportation sector (e.g., new liquid fuels) has the potential to impact several, or all, elements that comprise this sociotechnical configuration.

Fuel transitions in the transportation sector are the focus of this thesis. More specifically, the increasing consumption of biofuels in the transportation sector, as mandated by the RFS, is examined. This mandated biofuels transition will undoubtedly require substantial investments in a relatively short period of time in order to develop, or modify, the necessary infrastructure, fuel and vehicle technologies, and other elements that link together to deliver transportation services. With a well-developed, efficient, and expensive, petroleum-based infrastructure in place, many barriers must be overcome for biofuels to play a significant role in the transportation sector.[4] Identifying and understanding the barriers to a biofuels transition is the objective of this thesis.

1.5 Thesis Overview

Although fuel transitions may seem daunting and unfamiliar, the U.S. transportation sector has undergone numerous transitions in the past, including the introduction of unleaded gasoline, the shift from methyl-tertiary butyl ether (MTBE) to ethanol as the predominant gasoline oxygenate, and the recent mandated introduction of ultra-low sulfur diesel (ULSD). Many pertinent lessons can be derived from these historical transitions and used to identify and assess barriers facing the adoption of

[4] Motor gasoline and DFO fuels are the primary liquid fuels consumed in the U.S. These fuels are used primarily to power transportation activities. In addition, by mandating the consumption of biofuels in the transportation sector, the RFS has the greatest potential to impact the motor gasoline and DFO sectors. Therefore, throughout this thesis, the phrases "liquid fuels sector," "transportation sector," and "motor gasoline and DFO sectors" are used more-or-less interchangeably.

alternative fuels (i.e., biofuels) and to understand how such a transition might unfold. A review of historical transitions is presented in chapter 2, with a focus on changes to motor gasoline and distillate fuels in the U.S. liquid fuels sector over the last half century. Details on the policies, economic impacts, and technological advancements that occurred over this time are identified and analyzed in the context of the new biofuels mandate.

Computer models can also serve to explore the implications of fuel transitions. In order to better understand the barriers associated with fuel transitions, and to identify options for overcoming these barriers, many recent research efforts have used sophisticated modeling techniques to analyze energy transitions. Chapter 3 reviews a number of these recent modeling efforts with a focus on understanding how these methodologies have been applied, or may be adapted, to analyzing a transition to biofuels. Although the focus of this thesis is on biofuels, several models reviewed in chapter 3 focus on a transition to hydrogen fuel and vehicle technologies in the transportation sector.

Finally, a set of scenarios was developed to explore potential pathways and barriers to a biofuels transition. These scenarios were created from a high-level model of the liquid fuels sector, called the Liquid Fuels Transition (LiFTrans) model. This model was developed specifically as a part of this thesis, and is described in detail in chapter 4. Results from the model, i.e., the biofuel transition scenarios, are discussed and analyzed, with the objective of revealing potential barriers to a biofuels transition.

Chapter 2. Historical Fuel Transitions

"That the automobile has practically reached the limit of its development is suggested by the fact that during the past year no improvements of a radical nature have been introduced." – Scientific American, January 2, 1909

2.1 INTRODUCTION

The U.S. liquid fuels sector has undergone numerous transitions over the last several decades. Major transitions in the sector will be reviewed, with a focus on identifying the following characteristics and parameters:

- motivating factors for the transition, such as environmental, public health, economic, and energy security priorities;
- pertinent market and policy mechanisms that drove change;
- penetration rates into the fuel market (e.g., the rate of change);
- infrastructure changes and investments that were required in the petroleum industry, distribution and retail networks, and end use industry (i.e., engine and vehicle manufacturers) because of the transition;
- impediments encountered during the transition.

Key takeaways and lessons from these case studies will be discussed. The chapter begins with a review of major transitions in the motor gasoline sector, starting with the transition to unleaded gasoline. Section 2.3 reviews sulfur reduction transitions in the distillate fuel oil (DFO) sector. The chapter concludes with a section discussing the implications of transitions, with the goal of illuminating key forward-looking lessons that serve to identify potential barriers along the pathway to a transition to biofuels.

2.2 U.S. Motor Gasoline Sector

2.2.1 Leaded to Unleaded Gasoline

This section examines the introduction of unleaded gasoline in the U.S., which spanned nearly 20 years following the passage of the Clean Air Act (CAA) of 1970. The following discussion does not attempt to provide a full historical account of the leaded gasoline history. Sperling and Dill highlighted the utility of this case study nearly 20 years ago [29]: "[The] government-orchestrated transition to unleaded gasoline serves as a…model for the United States and other countries for the introduction of nonpetroleum fuels." As the U.S. works to introduce greater volumes of biofuels in the coming decade(s), this statement is more pertinent than ever.

Leaded gasoline made its entry into the transportation fuel market in the early 1920s as a consequence of the phenomenon known as engine knock. Although not a common problem with engines of that day, engine knock prevented the development of more efficient and powerful high-compression engines [30]. "Knock" is the name given to the noise that is transmitted through the engine when spontaneous ignition of a portion of the unburned fuel-air mixture occurs before the piston is at top-dead-center. Intense and sustained knock can result in a range of symptoms, from minor ones, such as overheating, loss of power, and reduced efficiency, to complete and immediate engine failure [31]. Engine knock can be prevented by utilizing fuels with higher octane ratings,[5] through engine redesign, or a combination of the two.

A solution to the knock problem would allow engines to operate at higher compression ratios leading to greater power output and fuel efficiency. With this goal in mind, a team of scientists and engineers at the GM Corporation, headed by Thomas Midgley, Jr., were tasked with solving the problem. Using the periodic table of the elements as their guide, the team of researchers resorted to the method of elimination to identify various chemical components that would reduce the tendency to knock. They eventually discovered the anti-knock quality of lead, specifically in the form of tetraethyl

[5] The ability of a fuel to resist knock is indicated by its octane number: higher octane numbers indicate greater resistance to knock.

lead (TEL), an organometallic compound with the formula $(CH_3CH_2)_4Pb$ [30]. The precise mechanism by which TEL controls knock is not fully known; it is generally agreed that the compound decomposes into lead oxide and inhibits the reaction that leads to auto-ignition of the fuel-air mixture [31].

Although other additives were being researched at the time, it seems that no other additive could compete on price. Researchers had experimented with low percentage additives, such as TEL and other organometallics, and high percentage additives, such as benzene and alcohols.[6] In fact, Midgley and his team carried out extensive research with high percentage blends and favored ethanol, even over TEL. However, the supply of ethanol in the 1920s and the production and use of alcohol during the prohibition era presented major obstacles [30].

The first public sale of 'ethyl' gasoline—the marketing name given to leaded gasoline—occurred on February 1, 1923 in Dayton, OH at 25 cents per gallon (regular gas cost 21 cents per gallon). By 1936, 90 percent of the gasoline sold in the U.S. contained TEL; by 1963 this figure had risen to greater than 98 percent [30]. Leaded gasoline paved the way for high performance engines that automobile manufacturers sought to produce. But, as illustrated in Figure 2-1, the use of lead in gasoline quickly dropped in the early 1970s.

---

[6] Low-percentage additives serve to inhibit knock when blended in very small quantities with gasoline, e.g., from parts-per-million levels to less than 2% by volume. High-percentage additives must be blended in much greater quantities, e.g., 10% to 20% by volume.

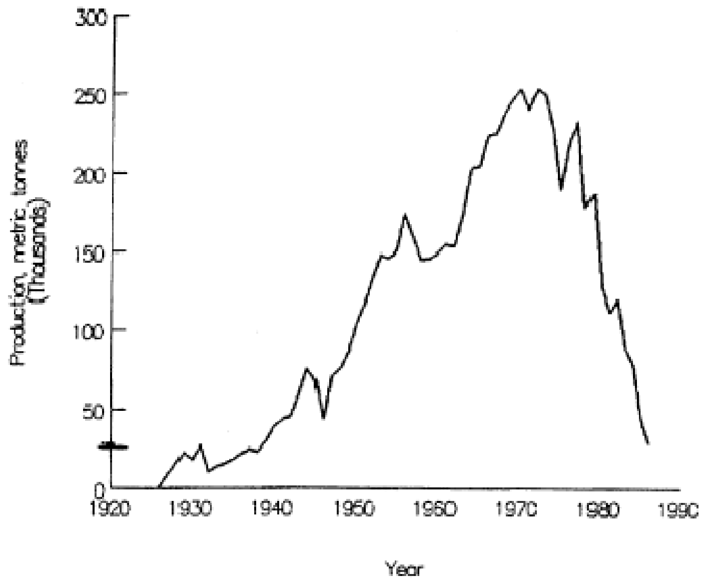


Figure 2-1. Consumption of lead in gasoline dropped rapidly after 1970 [30].

Mounting concerns about urban air pollution led to the passage of the CAA of 1970 and the establishment of the Environmental Protection Agency (EPA). The CAA introduced rules requiring new automobiles (starting in 1975) to use catalytic converters to control emissions of carbon monoxide (CO), nitrogen oxides (NOx), and hydrocarbons (HCs). Unleaded gasoline was a must for vehicles equipped with catalytic converters since various trace metals, including lead, inactivate the catalyst [31]. Simultaneously, the toxic nature of lead in the environment had gradually gained the attention of the public.

Section 211 (c)(1) of the CAA gives the EPA's Administrator broad authority to "control or prohibit the manufacture…or sale of any fuel additive" if its emission products (1) cause or contribute to "air pollution which may be reasonably anticipated to endanger the public health or welfare," or (2) "will impair to a significant degree the performance of any emission control device or system…in general use" [32]. Since the use of leaded gasoline "will impair to a significant degree" the performance of catalytic converters, the second condition was used by the EPA to mandate the phase out of lead.

It was not until the EPA later accelerated the phase out of lead in the 1980s that the first condition was cited as a major concern.

2.2.1.1 The Phasing Out of Lead in Gasoline

The initial phase down of lead was mandated through so-called 'command-and-control' measures taken by the EPA. On July 1, 1974, the EPA required all retailers that sold 200,000 gallons or more of gasoline to provide unleaded gasoline and design fuel nozzles so that cars with catalytic converters could accept only unleaded gasoline. Similarly, car manufacturers were required to design tank filler inlets to accept only unleaded gasoline and to apply "Unleaded Gasoline Only" labels on cars equipped with catalytic converters, which would arrive on the market with 1975 models [33, 34].

To further promote the production of unleaded gasoline, EPA implemented performance standards requiring refineries to decrease average lead content of all gasoline (i.e., a pooled average of lead content in leaded and unleaded gasolines). These performance standards took effect on October 1, 1979, and required a pooled average of 0.5 grams of lead per gallon for individual facilities. The standards were less stringent for small refineries (see Table 2-2 for details) since small facilities were apparently less capable of producing gasoline without lead.[7] This averaging method provided refiners with the incentive to increase unleaded production while not necessarily removing lead from their leaded gasoline. Despite this shortcoming, total lead usage still decreased as old vehicles were retired and replaced by new vehicles equipped with catalytic converters [33, 34].

The next set of rules, implemented on November 1, 1982, limited the allowable content of lead in leaded gasoline to a quarterly average of 1.1 grams per gallon of leaded gasoline (gplg). Small refineries again faced less stringent standards until 1983. This new rule no longer allowed the averaging, or pooling, of leaded and unleaded gasoline

---

[7] Section 2.2.1.2 provides details on the approaches taken by refiners to meet the increasingly stringent performance standards, and to produce unleaded gasoline with performance characteristics similar to leaded gasoline.

production, thereby forcing a true reduction in the concentration of lead in leaded gasoline [33, 34].

Despite the progress made in removing lead from gasoline, evidence on the health effects of lead in the environment was mounting. Between 1983 and 1985, the EPA conducted an extensive cost-benefit analysis of further tightening the standards to 0.1 gplg by 1988. In 1985, the EPA released a Regulatory Impact Analysis (RIA) estimating benefits in four major categories: blood pressure-related health effect in adult males due to lead; children's health and cognitive effects associated with lead; damages caused by excess emissions of HC, NOx, and CO from misfueled vehicles;[8] and impacts on maintenance and fuel economy of vehicles fueled with leaded gasoline [32].

The various benefits of the lead phase out were monetized and compared to estimated costs that would be borne by the refining industry to meet the 0.1 gplg standard. Table 2-1 summarizes the results of the cost-benefit analysis. Despite the substantial costs that would be placed on the refining industry, the EPA estimated that the benefits would outweigh the costs by as much as 10 to 1 [32]. On January 1, 1985, the new rule was introduced, phasing lead down to 0.1 gplg at the start of 1986.

To help ease the transition for refineries, the EPA permitted both trading and banking of lead permits through a system of interrefinery averaging. Trading of lead credits among refineries was allowed from late 1982 through the end of 1987, after which each refinery was required to comply with the 0.1 gplg standard. Banking was allowed only from 1985 to 1987. This marketable permit system alleviated some of the financial burden facing small refineries, and it allowed the refining industry a measure of flexibility in allocating the reduction among firms and in allocating investments over time, yielding a more cost-effective reduction [33, 34].

On January 1, 1996, the EPA banned the sale of leaded fuel for use in on-road vehicles. The EPA allowed the continued sale of leaded fuel for off-road uses, including

[8] Misfueling refers to the use of leaded gasoline in vehicles equipped with catalytic converters. Although some vehicle owners were concerned about knock, misfueling was attributed primarily to price differentials between leaded and unleaded gasoline at the retail level. Despite the smaller tank inlet fittings on new vehicles, owners could easily remove the fitting and thus fill their tanks with the cheaper and more familiar leaded gasoline.

aircraft, racing cars, farm equipment, and marine engines [35]. Through a combination of command-and-control and market-based policy mechanisms, the EPA successfully removed lead from gasoline in the U.S. over a period of two decades.

During the two decades of phasing out lead, a price differential existed between leaded and unleaded gasoline (see Figure 2-2). This differential raised concerns among economists, who were involved in the 1985 EPA study, that the study's model was underestimating the cost of replacing lead as an octane enhancer. The EPA model estimated that unleaded gasoline would cost approximately 2 cents per gallon more to produce; this estimate was consistent with various indicators in the market, such as the price at which lead permits were trading and prices on the wholesale markets. Most of the increase took place at the retail level, where leaded gasoline was advertised at a lower price to attract customers [36].

Borenstein estimated that overall price differences due to both price discrimination and differential production costs slowed the phase out of leaded gasoline by about 4 years [37]. Different taxation policies, in combination with phase out mandates, contributed to the more rapid adoption of unleaded gasoline in many European nations in the 1980s and 90s [38].

The effect of the CAA and EPA policies on lead in gasoline is very simply summarized in Figure 2-3—a chart illustrating the adoption rate of unleaded gasoline in the motor gasoline market. Table 2-2 provides a concise, chronological summary of the lead standards.

Table 2-1. An EPA Cost-Benefit Analysis in 1985 estimated that costs to the refining industry would be outweighed by various benefits (millions of 1983 dollars) [32]. The abrupt increase in net benefits from 1985 to 1986 occurs due to the lead standard being reduced from 0.5 to 0.1 gplg.

Monetized Benefits	1985	1986	1987	1988	1989	1990	1991	1992
Children's health effects	223	600	547	502	453	414	369	358
Adult blood pressure	1,724	5,897	5,675	5,447	5,187	4,966	4,682	4,691
Conventional pollutants	0	222	222	224	226	230	239	248
Maintenance	102	914	859	818	788	767	754	749
Fuel economy	35	187	170	113	134	139	172	164
Total Monetized Benefits	2,084	7,821	7,474	7,105	6,788	6,517	6,216	6,211
Total Refining Costs	96	608	558	532	504	471	444	441
Net Benefits	1,988	7,213	6,916	6,573	6,284	6,045	5,772	5,770
Net Benefits Excluding Blood Pressure	264	1,316	1,241	1,125	1,096	1,079	1,090	1,079

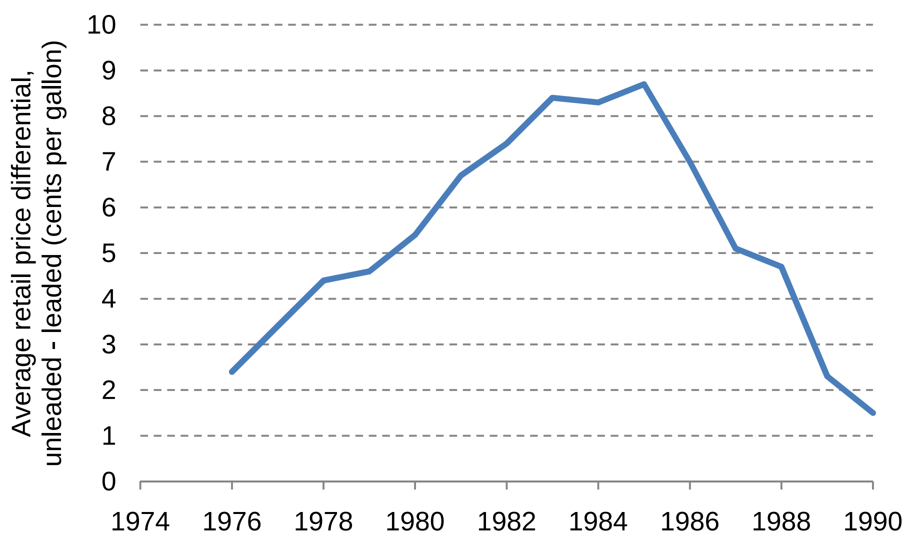


Figure 2-2. Unleaded gasoline was priced at a premium over leaded gasoline during the transition to unleaded gasoline [39].

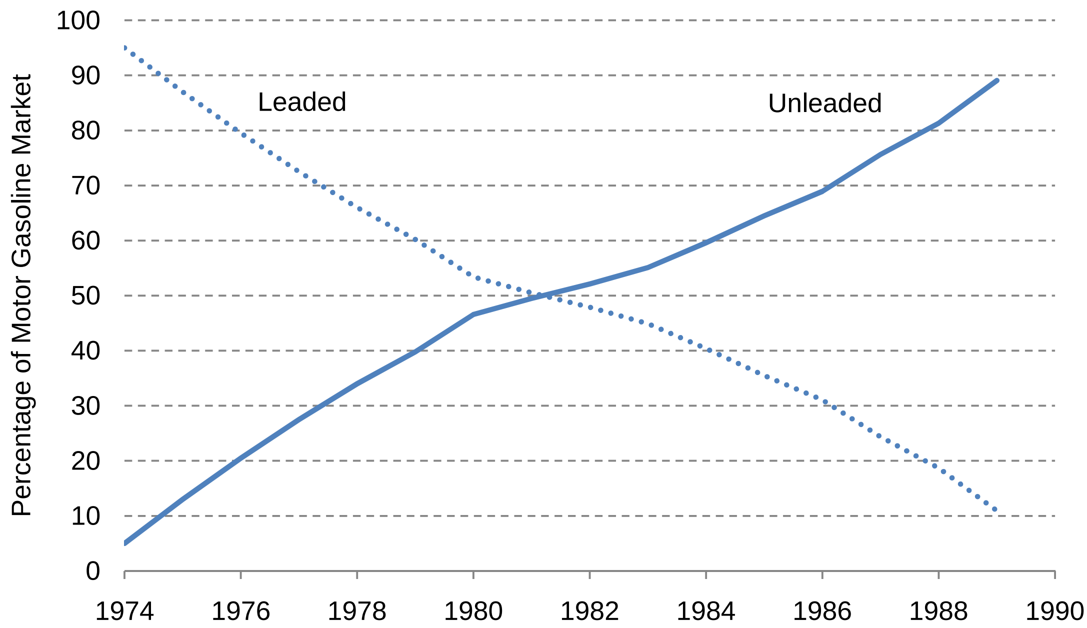


Figure 2-3. The transition to unleaded gasoline spanned over 15 years [29, 40-42].

Table 2-2. Lead standards promulgated by the EPA from 1974-1996 [33, 34].

Deadline	Standard	Small Refinery Exceptions
July 4, 1974	Gasoline retailers must offer unleaded gasoline for use in cars with catalytic converters.	
October 1, 1979	Refineries must not produce gasoline averaging more than 0.5 glpg per quarter, pooled (leaded and unleaded).	Small refineries (≤ 50 MBD crude oil capacity, owned by company with ≤ 137.5 MBD capacity) are subject to less stringent standard of 0.8-2.65 glpg varying by capacity.
November 1, 1982	Refineries must meet a leaded gasoline standard of 1.1. Interrefinery averaging of lead rights is permitted among large refineries and among small refineries, but not between refineries of different sizes.	Very small refineries (≤ 10 MBD gasoline production, owned by company with ≤ 70 MBD production) are subject to a less stringent pooled standard of 2.16 or 2.65 varying by capacity.
July 1, 1983	Very small refineries are also subject to a standard of 1.1 (leaded). Averaging is permitted among all refineries.	
January 1, 1985	During 1985 only, refineries are permitted to 'bank' excess lead rights for use in a subsequent quarter.	
July 1, 1985	The standard is reduced to 0.5 (leaded).	
January 1, 1986	The standard is reduced to 0.1 (leaded).	
January 1, 1988	Interrefinery averaging and withdrawal of banked lead usage rights are no longer permitted. Each refinery must comply with the 0.1 standard.	
January 1, 1996	Lead additives in motor gasoline are prohibited.	

Note: glpg = grams of lead per gallon; MBD = thousand barrels per day.

2.2.1.2 Impacts to Industry

Up to this point, only the history of leaded gasoline and the policies used to phase out lead have been discussed. The impacts on industry, including refiners, distributors and marketers, and automobile manufacturers are addressed next.

At the time, the catalytic converter was viewed as the only technology available to the automotive industry to meet the new emissions requirements under the CAA. Since catalytic converters are rendered ineffective when exposed to lead over extended periods, the automotive industry inevitably became a major proponent of unleaded gasoline. In addition, the use of unleaded gasoline was expected to lower vehicle maintenance costs and increase fuel economy [29]. It is interesting to note that the EPA RIA included these benefits (see Table 2-1). The reduced maintenance costs, enjoyed by vehicle owners, were a direct result of the elimination of lead and the associated impacts that lead has on exhaust system components, spark plugs, and oil quality.

Before 1975, the petroleum industry had concerns that after making large capital investments to produce unleaded gasoline it would then find that there was little demand for the new product. The automotive industry smoothed this transition by producing pre-1975 vehicles that could operate on either fuel, helping to initiate a market for the new fuel. These 'dual-fuel' vehicles were designed with slightly lower compression ratios and were upgraded with exhaust valves with improved metallurgy to mitigate concerns about valve seat wear [29].

The removal of lead did not negate the need for refiners to boost octane in gasoline. Refiners had (and still have) two basic options for increasing the octane of gasoline without lead additives. They can employ the more intensive refining techniques of alkylation, isomerization, catalytic cracking and reforming to produce hydrocarbons with higher octane (e.g. highly branched alkanes, benzene and other aromatics). The other approach is to utilize alternative additives, such as methyl tertiary-butyl ether (MTBE), ethyl tertiary-butyl ether (ETBE), and alcohols such as methanol and ethanol [29, 34, 43]. Each of these alternatives was expected to increase operating costs and require investments in the refining industry.

Prior to any regulation being in place, there were many attempts made at estimating these anticipated costs. In 1967, API estimated that the transition to unleaded gasoline would cost refiners a total of $4.2 billion [44]. The study estimated that overall average production costs of gasoline would increase about 2 cents per gallon. In 1971, a consultant study for the EPA stated that "the most significant impact of a lead removal program on the domestic petroleum industry is the requirement that more capital be spent on refineries over the next 10 years". Other estimates ranged from about $4 billion to $6 billion [29].

The 1985 EPA RIA provided a very comprehensive assessment of the costs that would be required by the industry in reducing lead content from 1.1 to 0.1 gplg. Again referring to Table 2-1, the EPA estimated that the new rule would cost the refining industry approximately $500 million per year from 1985 to 1992 (in 1983 dollars). As mentioned earlier, the EPA estimated that these refining costs would translate into a production cost increase of 2 cents per gallon over leaded gasoline, which falls in line with API's estimate from 1967.

A study completed by the Energy Information Administration (EIA) that reviewed the state of the refining industry in the 1980s helps to explain the difficulty in assessing the costs directly attributable to the phase out of lead [40]:

> The overall financial performance and investment patterns for the refining/marketing sector in the 1980's were heavily influenced by several factors, including the decontrol of domestic crude oil prices in 1981, the severe drop in crude oil prices in 1986, changes in product demand and crude oil supply, and the introduction of more stringent environmental regulations.
>
> Factors which drove the rise in investment throughout the decade include shifting product demand away from heavy fuel oils to light products, the increased availability of high-sulfur crude oils, the price spread between light and heavy crude oils, and restrictions on lead content. The anticipation of additional environmental regulations governing motor gasoline vapor pressure and reducing the sulfur content of diesel fuel were other factors that induced investments.

The "restrictions on lead content" were but one of many challenges facing the industry in the 1980s, and thus it is difficult to allocate refinery capital investments to the lead phase-out alone. Although these excerpts illustrate the difficulty in assigning specific costs to the lead standards, it is worthwhile to present data on investments made by the industry during this time period. Figure 2-4 shows the annual investments made by FRS refineries[9] from the late 1970s to the late 1980s. FRS refineries accounted for 75 to 80% of total domestic refining capacity during the 1980s, and therefore are a reasonable proxy for the industry as a whole. Annual investments ranged from approximately \$1.5 billion to \$5 billion (constant 1982 dollars). By comparing the annual EPA cost estimates (Table 2-1) against the actual investments made by the industry, it is possible to conclude that investments needed to meet lead standards made up a significant portion of overall industry investments during this time period.

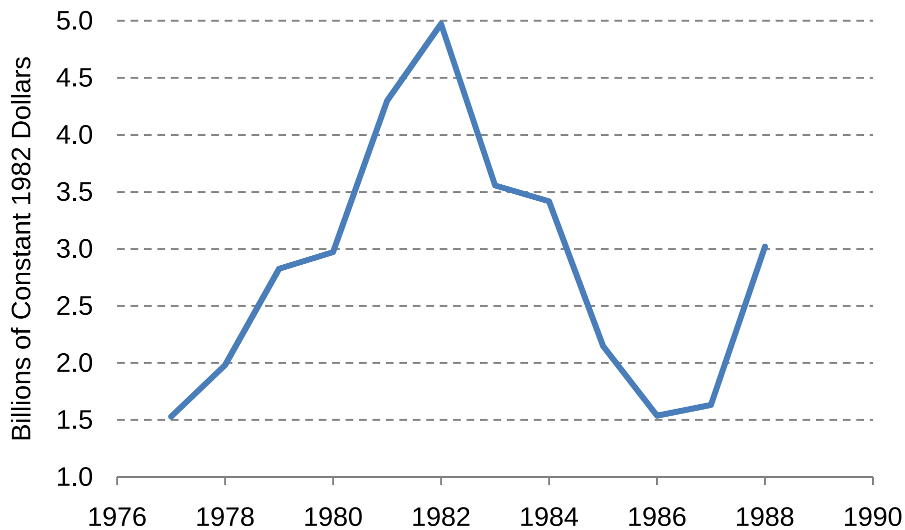


Figure 2-4. Investments in Domestic Petroleum Refining for FRS Companies ranged from \$1.5 to \$5.0 billion annually during the transition to unleaded gasoline, which spanned from approximately 1975 through 1990 [40].

Despite the lack of technical challenges facing the distribution and marketing system (unleaded and leaded gasoline were both compatible with pipelines, tanks, tanker trucks, railcars, etc.), there were many logistical challenges associated with the delivery

[9] FRS companies include those refineries that report financial data through EIA's Financial Reporting Systems (FRS).

and storage of both leaded and unleaded gasoline. For example, precautions had to be taken to ensure that unleaded gasoline did not exceed the EPA standards; pipeline procedures had to be modified to minimize contamination; and separate storage facilities were necessary throughout the distribution system. At the retail level, as mentioned previously, new dispensing nozzles had to be designed and installed for fueling unleaded vehicles. According to Sperling and Dill, the total cost of adapting the distribution system to unleaded gasoline was large but never specified; however, because thousands of companies were involved, the costs were widely distributed. Costs incurred at retail stations alone, not including the distribution system, were estimated in 1978 at $5,951 per outlet [29].

In summary, it would be very challenging to accurately quantify the investments made in the industry during the transition to unleaded gasoline that can be directly attributed to the phase out of lead. Based on the various industry and government estimates presented above, the total investments over two decades could have ranged from as little as $4 billion to greater than $10 billion dollars. This range of estimates equates to approximately $10 billion to greater than $20 billion in present day dollars.

2.2.2 High-Octane Hydrocarbons in Gasoline

As discussed in the previous section, as lead additives were reduced in leaded gasoline, and eliminated in unleaded gasoline, refiners sought ways to recover the octane lost through the removal of lead additives. Changes in gasoline composition were once again necessary. Refiners reverted to using high-octane hydrocarbons such as alkylated aromatics, olefins, and branched paraffins. Oxygenated compounds also increase octane and were being utilized as early as the late 1960s. Initially, refiners turned to butane, and other short-chain or lower paraffins,[10] and aromatics[11] to boost octane. Lower paraffins, such as butane, provided a cost-effective way to enhance octane by boosting the octane at relatively low concentrations [45]. However, these lower paraffins evaporate readily and volatilize other reactive hydrocarbons in gasoline. Both summer and winter gasolines

---

[10] Paraffins are alkane hydrocarbons with the general formula C_nH_{2n+2}.

[11] Aromatics are hydrocarbon compounds containing one or more benzene rings.

followed an upward trend in vapor pressure until approximately 1989 when there was a rapid drop for summer gasolines in response to federal vapor pressure regulations (discussed below). Figure 2-5 illustrates these trends in vapor pressure, which were directly related to the content of butane and other lower paraffins in gasoline used to meet octane demands throughout the 1980s [46].

Some of the worst ozone excursions on record were observed during the summer of 1988. These events led to speculation that evaporation of high-volatility summer gasoline was a major contributor to the VOC emissions that gave rise to these ozone excursions. Following initiatives taken by individual states, the EPA promulgated a rule setting vapor pressure (i.e., volatility) limits on gasoline sold during the ozone season throughout the nation starting in 1989; these limits were redefined and tightened for 1992 and later years [45]. Under the CAA Amendments of 1990, the EPA promulgated the Phase I and II Volatility Regulations for Gasoline and Alcohol Blends. Phase I and II Volatility Regulations required gasoline Reid Vapor Pressure (RVP)[12] not to exceed 10.5/9.5/9.0 and 9.0/7.9 psi, respectively, depending on the state and month. The more stringent limits (e.g., Phase II Regulation of 7.9 psi) are often applied in the summer months when gasoline volatility increases due to higher average ambient temperatures. Gasoline containing ethanol at 9 to 10% by volume was given a 1.0 psi allowance (e.g., Phase II Regulations increase to 10.0/8.9 psi), due to the low-level blended fuel having a higher volatility relative to gasoline alone [47]. California led the nation by enacting similar volatility regulations starting in 1971.

[12] RVP is a common measure of gasoline volatility based on the test method ASTM D323.

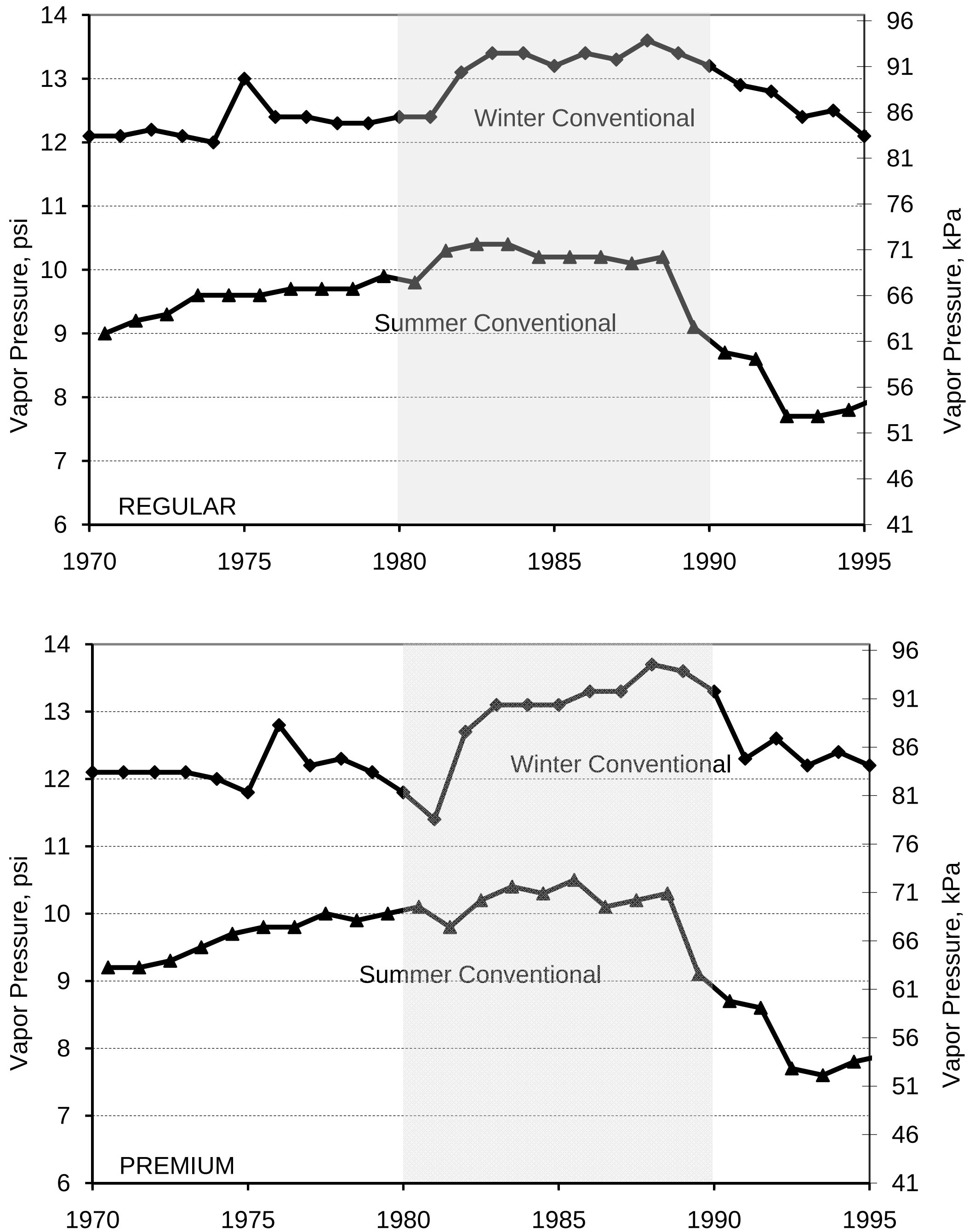


Figure 2-5. U.S. National average vapor pressure trends for regular and premium grade gasolines serve as an indicator of the use of lower paraffins in gasoline [48].

Although the lower paraffins helped to recover some of the octane rating, refiners needed additional high-octane components to further boost octane. Unleaded regular- and premium-grade gasolines initially had substantially higher aromatics content than the leaded grades they replaced before dropping. Figure 2-6 illustrates these trends in aromatics content in gasoline. Following an initial increase, aromatics content followed a slight downward trend through the 1980s and 1990s. Gibbs partially attributes this reduction to dilution caused by the increased use of oxygenates for octane enhancement and to meet federal oxygenated gasoline requirements [46]. Decreases in aromatics content may also be due to limitations placed on benzene as an air toxic by the CAA Amendments of 1990.

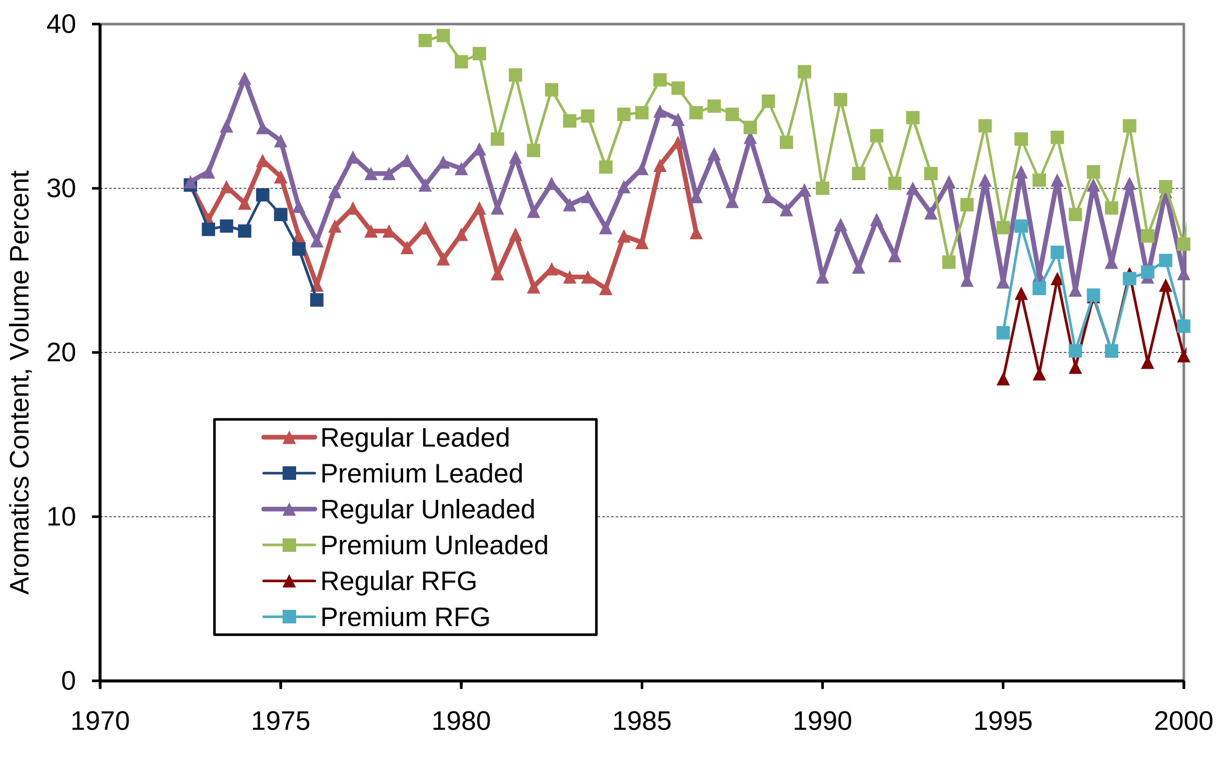


Figure 2-6. U.S. National average aromatics content increased in the unleaded gasolines that replaced the leaded gasolines [48], e.g., regular unleaded is shifted up relative to regular leaded from 1973 through 1986.

The impacts of these fuel modifications on the motor gasoline sector were confined to the refining industry. The altered composition of gasoline, with an increased content of lower paraffins and aromatics, did not impact the distribution, retail, and end use stages of the motor gasoline supply chain. Refiners, in their drive to recover the octane lost through the reduction and removal of lead additives, revamped their operations to alter the formulation of gasoline. The necessary investments made by the refiners to initially recover the octane of gasoline during the lead phase down through the use of higher octane hydrocarbons are likely encompassed within the refinery investments made throughout the 1980s, as discussed in the prior section on the transition to unleaded gasoline (see section 2.2.1.2). Quantifying the economic costs attributable to these fuel modifications was considered to be beyond the scope of this thesis.

2.2.3 Oxygenates in Gasoline

The two most common oxygenates used as additives in gasoline are methyl-tertiary butyl ether, or MTBE ($CH_3OC(CH_3)_3$), and ethanol (C_2H_5OH). These oxygenates are used to increase the octane rating of gasoline and to reduce the formation of air pollutants, such as carbon monoxide (CO). Alternative, less common oxygenates include methanol (CH_3OH), tertiary-amyl methyl ether (TAME), ethyl-tertiary butyl ether (ETBE), and di-isopropyl ether (DIPE). These oxygenates have been far less common in the gasoline pool, aside from a short-lived interest in methanol as a gasoline substitute and oxygenate during the 1980s. Figure 2-7 shows the total amount of oxygenate consumed in the US from 1980 to present day, relative to the total motor gasoline supply. The data may slightly underestimate the total oxygenate as this data set includes only the ethanol and MTBE supply. Regardless, the total oxygenate supply has grown from essentially 0% to over 7% of the total motor gasoline supply in the last three decades. The figure also illustrates a transition that occurred during the first decade of the 21st century—the transition from MTBE to ethanol as the primary oxygenate additive in gasoline. This transition will be discussed further in the next section.

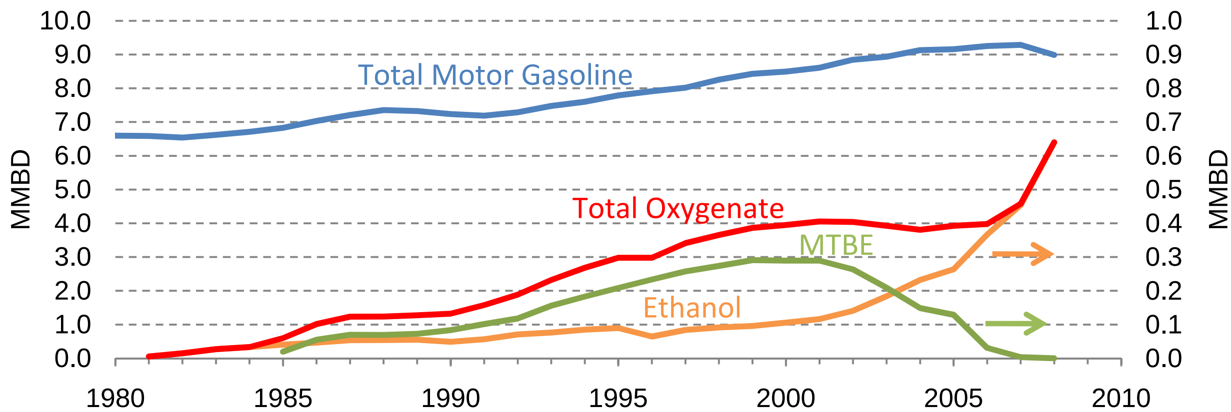


Figure 2-7. Total oxygenate supply (right axis) has grown steadily for three decades to make up a substantial share of the total motor gasoline supply (left axis) [42, 49-52]. All data series represent the product supply consumed in the U.S. in million barrels per day (MMBD).

Along with the high-octane hydrocarbons, oxygenated compounds were being used in small quantities as high-octane blending components as early as the late 1960s. The EIA apparently did not track oxygenate production or supply in the motor gasoline sector prior to the 1980s, possibly a reflection of the small quantities used prior to 1980. As the lead phase down progressed through the 1980s, and refiners worked to maintain the octane performance of gasoline, the regulation of fuel properties was substantially expanded with the passage of the CAA Amendments of 1990 (CAAA 1990). The CAAA 1990 mandated the Federal Reformulated Gasoline (RFG) program and the Federal Oxygenated Fuels (Oxyfuels) program. The RFG program commenced in late 1994 (Phase I) and was made more stringent in 2000 (Phase II); the Oxyfuels program started earlier in 1992. The California Air Resources Board (CARB) implemented its own RFG program, which commenced in 1992, nearly 3 years prior to the Phase I program promulgated by the EPA. CARB also mandated wintertime oxygen content starting in 1992 [45, 46, 53]. By mandating the use of oxygenates, these programs rapidly expanded the use of oxygenated compounds in motor gasoline during the 1990s (see Figure 2-7).

Like the volatility regulations, the Oxyfuels program was justified based on the success of winter gasoline oxygenate programs established by some states in the late 1980s [45]. This program seeks to lower motor-vehicle emissions of CO to avoid nonattainment of the National Ambient Air Quality Standards (NAAQS) for CO, and to help nonattainment areas move towards attainment. Because CO pollution is typically more severe in the winter months,[13] the Oxyfuel program requires gasoline to contain 2.7 percent oxygen content (by weight) during the wintertime. When the Oxyfuel program commenced in 1992, 36 areas[14] implemented the program; only 8 areas implemented the program during the winter of 2007/2008 [54]. Ethanol has served as the additive of choice for most oxyfuel areas [55].

In contrast, the RFG programs tend to regulate gasoline sold during the summer ozone season. The programs set content requirements for oxygen, benzene, and aromatics, and requires reductions in levels of NOx, toxics, and VOC emissions relative to a 1990 fuel baseline. These programs (Federal and CA) are aimed at reducing light-duty vehicle (LDV) emissions of VOC, CO, NOx, and air toxics. According to the EPA, RFG is gasoline that is blended such that it significantly reduces VOC and air toxics emissions compared to conventional gasoline. Since the fuel properties of RFG are well within those exhibited by conventional gasoline, the EPA explained, when introducing the program, that the RFG program is a "new program", but that RFG is not a "new gasoline" [56]. Nine metropolitan areas were initially mandated under the RFG program, although any nonattainment areas are able to voluntarily opt in to the program. Prior to 2006, the RFG program required a minimum of 2.1 percent oxygen by weight (average). Figure 2-8 illustrates the rapid introduction of RFG in the motor gasoline sector. Following its introduction in December 1994, RFG use rapidly grew to over 30% of the

[13] In the winter months, lower temperatures during engine start up and cold operation can result in incomplete combustion, leading to the formation of CO emissions. Adding oxygenates to gasoline is thought to reduce emissions of CO, although the overall emissions benefits of gasoline oxygenates have been questioned. See, e.g., http://www.nap.edu/catalog.php?record_id=9461

[14] In regulatory terms, "area" refers to metropolitan statistical area (MSA) and consolidated metropolitan statistical area (CMSA), both of which are comprised of one or more counties.

sector by 1996; RFG continues to comprise approximately one third of the motor gasoline volume, with that share increasing slowly since 1996.

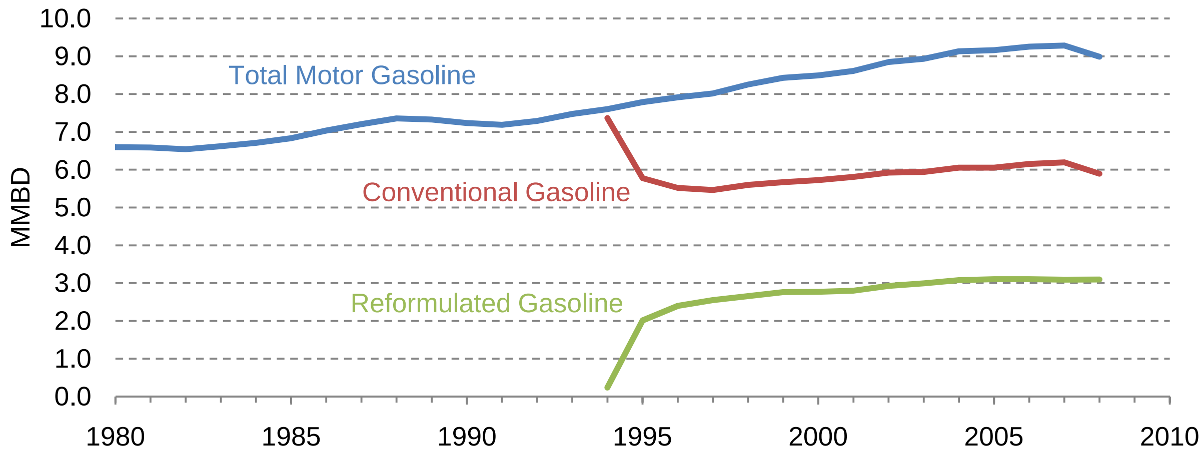


Figure 2-8. The RFG program currently comprises over one third of the motor gasoline market, with conventional gasoline comprising the remainder [42].

The quantity of oxygen in a fuel is typically expressed in terms of the percent by volume of oxygenated additive (i.e., vol % additive) or the percent of oxygen in the fuel by weight (i.e., wt % oxygen). The later quantity is used to specify oxygen content requirements in the RFG programs. MTBE is a larger compound relative to ethanol, yet both have only one oxygen atom in their structures. Therefore, a greater volume of MTBE is needed to obtain the same weight percent of oxygen than when blending with ethanol. Table 2-3 lists the amounts of ethanol and MTBE (by volume) needed to produce gasoline with a given oxygen content. To meet a specified percent of oxygen by weight, ethanol is blended at about 50% less volume percentage relative to MTBE. The RFG program mandated approximately 2% oxygen by weight, which requires 5.7% ethanol by volume and 11.2% MTBE by volume [45].

Table 2-3. The volume of MTBE needed to produce a specified oxygen content in gasoline is nearly double that of ethanol [45].

Wt % Oxygen	Vol % Ethanol	Vol % MTBE
1.0	2.85	5.6
1.5	4.3	8.3
2.0	5.7	11.2
2.5	7.1	13.9
3.0	8.6	16.7
3.5	10.1	18.9

Prior to the introduction of regulations mandating the use of oxygenates in gasoline, the use of oxygenates was quite limited. Refiners used conventional refining processes to produce high-octane hydrocarbons for blending with gasoline in order to recover the octane performance provided by lead additives. These processes, such as catalytic cracking, catalytic reforming, and isomerization, can often be more economical than those used to produce oxygenates. However, as the Oxyfuel and RFG programs were implemented, MTBE quickly became a dominant oxygenate in the gasoline pool.

According to the EPA, Arco Petroleum began selling an RFG-like gasoline in California in the late 1980s as a replacement for leaded gasoline. Arco's "EC-1" fuel, which utilized MTBE as an additive, was formulated specifically for older vehicles with high compression ratios demanding high octane gasoline. Other petroleum refiners began to follow suit. When CAA legislation was being debated in 1990, a number of provisions called for the use of alternative fuels to aid in reducing emissions. As a substitute for these non-petroleum fuels provisions, the petroleum and oxygenate industries lobbied in favor of an RFG program. Arguing that significant fleet turnover would be required to achieve emission reductions through the use of alternative fuels, they explained that RFG would be effective immediately in reducing emissions in the existing LDV gasoline fleet [57].

The petroleum industry favored MTBE for several reasons. First, the feedstocks used to produce MTBE are hydrocarbons—normal butane and methane. Methane is used to produce methanol; normal butane is isomerized to produce isobutylene; methanol and isobutylene are then reacted to form MTBE. Normal butane is a hydrocarbon present in both crude oil and wet natural gas, while methane is the primary hydrocarbon in natural gas. Second, MTBE can be blended with gasoline at a refinery and distributed through the existing infrastructure with no modifications. Since MTBE production is co-located with base fuel production, the need for new distribution infrastructure is also minimized. Therefore, the existing fuels industry loses little market share and experiences little disruption in operations when MTBE is used as an oxygenate additive in RFG; only a small shift from petroleum to natural gas is required to produce the additive. With the petroleum and oxygenate industries helping to implement the RFG program in the CAAA of 1990, MTBE use rapidly increased through the 1990s (see Figure 2-7). Estimates of the total amount of oxygenate in RFG and volumes of MTBE and ethanol as oxygenates in RFG, from the program's inception in late 1994 through present day, are shown in Figure 2-9.

In addition to increasing the use of oxygenates, the RFG program reduced aromatics content in the overall gasoline pool. Referring back to Figure 2-6, the aromatics content of premium and regular RFG is reduced relative to the average unleaded gasoline trends.

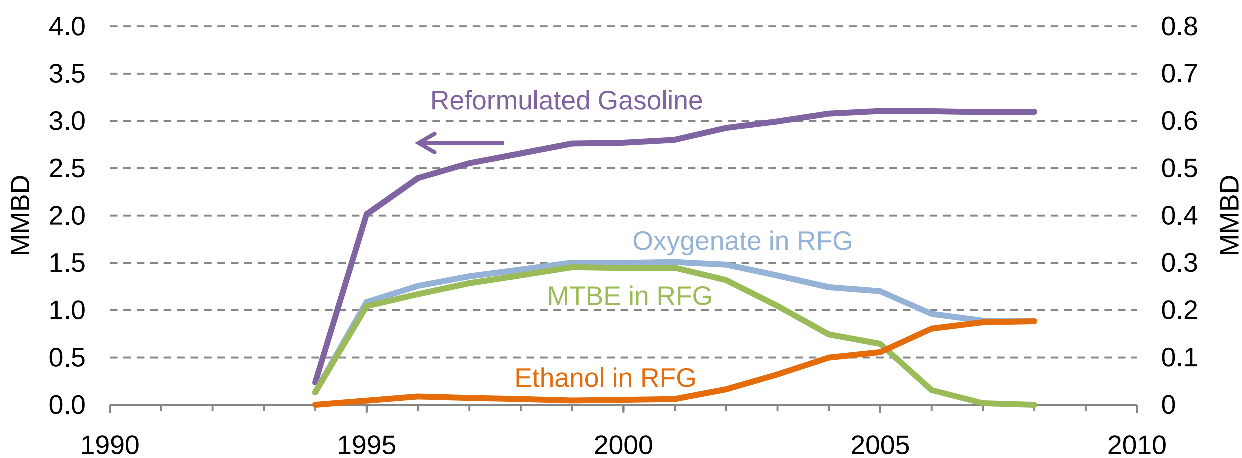


Figure 2-9. MTBE served as the predominant oxygenate in RFG throughout the 1990s [42, 49-52]. This figure does not account for the quantities of ethanol and MTBE consumed in the Oxyfuels program; data on the consumption of oxygenates in the Oxyfuels program could not be identified. To create this chart, it was assumed that the entire MTBE supply is blended in RFG with the balance being supplied by ethanol.

2.2.4 MTBE to Ethanol as the Dominant Gasoline Oxygenate

As MTBE became more ubiquitous throughout much of the nation's gasoline infrastructure, evidence of drinking water contamination—particularly in groundwater supplies—led to concern over its continued use. In 1999, the seminal report, "Achieving Clean Air and Clean Water: The Report of the Blue Ribbon Panel on Oxygenates in Gasoline [55]," marked the beginning of the end of MTBE's dominance of the gasoline oxygenate market—MTBE consumption reached its peak of 0.29 MMBD that same year and declined rapidly thereafter (see Figures 2-7 and 2-9). The independent Blue Ribbon Panel, appointed by then EPA Administrator, Carol Browner, found that detections of MTBE in drinking water primarily resulted in consumer odor and taste concerns and that MTBE had been found, in rare cases, at levels above the EPA's drinking water advisory and state standards. The Panel made the following recommendations, stressing that the actions should be implemented as "a single package" in order to simultaneously maintain air quality benefits and improve water quality protection without impacting the cost and supply of gasoline [55, 58]:

- remove the requirement for 2% oxygen in RFG from the CAA;
- enhance water protection programs (over 20 specific actions were specified);
- reduce MTBE use nationwide;
- maintain air quality benefits of RFG;
- support further research on MTBE and its alternatives.

The EPA did work to implement several recommendations made by the Blue Ribbon Panel. The agency supported legislation in Congress to phase down the use of MTBE as a fuel additive in gasoline and promote renewable fuels like ethanol [58]. However, no federal legislation aimed specifically at limiting MTBE use was ever passed. Despite inaction at the federal level, individual states implemented limits and bans on MTBE to prevent further contamination of water supplies. As of August 2007, 25 states had taken actions to limit or ban the use of MTBE and other similar oxygenates (e.g., other ethers) in gasoline [59]. Although Congress never passed legislation related to the use of MTBE, the Energy Policy Act (EPAct) of 2005 included a provision to eliminate the RFG oxygen content requirement from the CAA, as recommended by the Panel. The EPA proceeded to amend the RFG regulations, effectively removing the oxygen content requirement on May 5, 2006 [60].

Prior to the amendment of RFG regulations, most oil companies had announced their intent, and were already taking actions, to remove MTBE from their gasoline by the summer driving season of 2006. The companies' decisions were driven by three factors: (1) the state bans due to water contamination concerns, (2) liability exposure from adding MTBE to gasoline, and (3) the potential for additional liability exposure due to the elimination of the RFG oxygen content requirement in the EPAct of 2005 [61]. As refiners phased out their use of MTBE as an oxygenate additive in gasoline, domestically-produced, corn-based ethanol quickly became the primary substitute. With favorable federal and state tax incentives supporting domestic ethanol production, the refining industry turned to ethanol for RFG production to (1) maintain octane performance, (2) achieve air toxics reduction requirements, and (3) make up for lost volume (from the MTBE phase out) [62]. In addition, refiners were wary about turning to alternative ethers (e.g. ETBE) that could pose water contamination concerns similar to those evidenced by the use of MTBE.[15]

Figure 2-7 illustrates the overall transition from MTBE to ethanol as the dominant oxygenate in the motor gasoline sector, while Figure 2-9 illustrates this transition within the RFG portion of the sector. In 2008, 47 thousand barrels per day (MBD) of MTBE were produced in the US solely for export markets—no MTBE was consumed domestically.

As with the phase down of lead additives in gasoline, concerns arose about the phase down of MTBE as an oxygenate additive in gasoline [63, 64]. Much of this concern stemmed from a report published by the EIA in March 2006, titled, "Eliminating MTBE in Gasoline in 2006," which warned that the rapid transition from MTBE to

[15] As discussed in section 2.2.5, the Renewable Fuel Standard also played a role in the transition from MTBE to ethanol.

ethanol could "increase the potential for supply dislocations and subsequent price volatility on a local basis [61]." The EIA warning, aimed mostly at the East Coast and Texas RFG regions, pointed to several potential drivers for the supply and price concerns [61]. First, a net loss of gasoline production capacity would occur due to changes needed in RFG blendstocks to accommodate the differing properties of ethanol, particularly with its higher vapor pressure. Second, ethanol production capacity and distribution challenges were expected to create a tight ethanol market in the short term. Third, since ethanol would be blended solely at terminal facilities, limited resources and permitting problems would hinder gasoline suppliers' ability to install the necessary equipment for the storage and blending of ethanol. Finally, a shortfall in (RFG) import sources would result due to their inability to deliver RFG without MTBE or to produce the high-quality blendstock needed for ethanol blending.

With respect to the removal of the RFG oxygen content requirement, Lyondell Chemical, the nation's top MTBE Manufacturer at the time, responded harshly to the EPA rule, captured in the headline of an article published by Green Car Congress: "Top MTBE Manufacturer Slams EPA Ruling on Oxygenated Fuels [65, 66]." Well before the EPA ruling, Lyondell included a dissenting opinion in the Blue Ribbon Panel's "Achieving Clean Air and Clean Water" report in 2000. Based on the recommendations made by the Panel, Lyondell estimated that the recommended alternatives to MTBE would "impose an unnecessary additional cost of 1 to 3 billion dollars per year (3-7 c/gal. RFG) on consumers and society without quantifiable offsetting social benefits or avoided costs with respect to water quality in the future [55]." In Lyondell's response to the EPA ruling (to remove the RFG oxygen content requirement) in 2006, the company estimated that the "direct impact on the United States economy will be $6-$13 billion over a two-month spike, and a sustained increase of $350-$700 million per year (excluding impact of reduced economic activity due to higher gasoline prices) [65]." As with the Ethyl Corporation's experience during the lead phase down, Lyondell held a major stake in the MTBE industry and would be severely impacted by the MTBE phase down.

It is not entirely clear whether Lyondell's estimated impacts to the economy and the EIA's warnings were ever realized during the rapid transition from MTBE to ethanol. Figure 2-10 plots the trend in national average (real and nominal) gasoline prices from 2005 through 2007. Although the national average price may conceal evidence of localized price aberrations, it is clear that the phase out of MTBE and transition to ethanol did not cause gasoline prices to skyrocket—the average price appears to follow the normal summer driving season price increase that is experienced annually in the US. The peak in nominal price during the summer of 2006 increased by less than 8 cents relative to that of 2005; the peak in real prices were nearly identical [67].

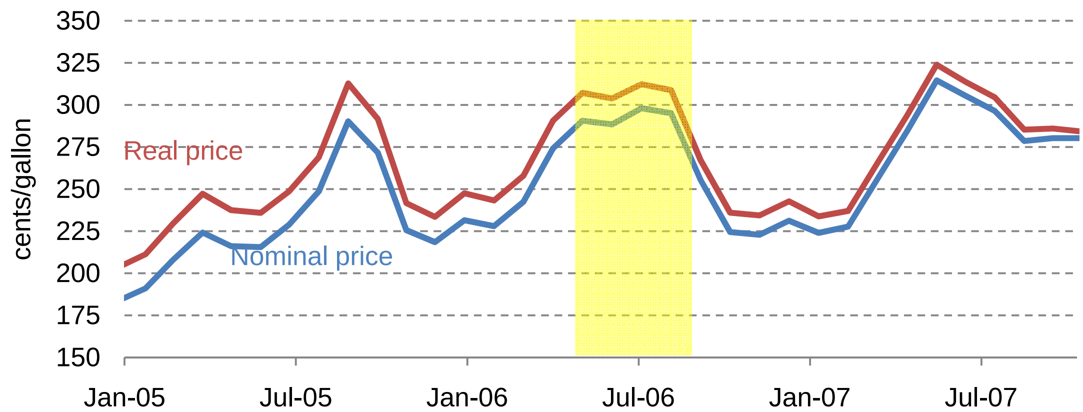


Figure 2-10. National average gasoline prices (real and nominal) during the summer of 2006 (shaded box) followed the normal summer driving season price hike [67].

In sharp contrast to Lyondell's concerns, a report prepared in March 2000 for the Governor's Ethanol Coalition—in response to the Blue Ribbon Panel report—stated that a transition from MTBE to ethanol would not result in increased gasoline prices and would result in positive economic impacts [68]:

> The cost to add the new ethanol capacity to replace MTBE is estimated at nearly $1.9 billion. The level of construction activity associated with this expansion combined with the increased demand for corn and other grain to produce the

> additional ethanol will add $11.7 billion to real GDP by 2004, increase household income by $2.5 billion, and generate more than 47,800 new jobs throughout the entire economy.

During a hearing before the Senate Environment and Public Works Committee in March 2006, the president of the Renewable Fuels Association, Bob Dinneen, explained that the industry had anticipated the transition and would be capable of handling the short-term challenges associated with the rapid increase in ethanol demand [64]. In a letter to the EIA, in response to the EIA's 2006 report on the transition, Mr. Dinneen explained that domestic ethanol producers, combined with ethanol imports, would be capable of meeting the new demand required by the RFG market [69, 70]. Two months later, in a hearing before the Energy and Commerce Committee, Mr. Dinneen suggested that the transition was nearly complete, and that the industry had continued to provide an adequate supply of gasoline without increasing prices [71]:

> As refiners have made the decision to remove MTBE from gasoline, ethanol has been there to replace the lost octane and volume of MTBE, without sacrificing the air quality benefits of the RFG program or increasing consumer costs. The transition from MTBE to ethanol is now largely complete, and is a testament to what can be accomplished when oil refiners, gasoline marketers and ethanol producers work together for the benefit of consumers.

To address the distribution challenges associated with moving ethanol to market, Dinneen explained that the ethanol industry had aggressively developed a "Virtual Pipeline." This "pipeline" moves ethanol through components of the distribution system that are compatible with the fuel: the rail system, barges, and trucks. By improving the logistics of ethanol distribution, the ethanol industry was able to efficiently move their product to new demand regions (i.e., RFG markets) during the transition without the aid of the petroleum pipeline infrastructure.

During an April 2006 press conference, EIA Administrator Guy Caruso stated that consumers should expect gasoline prices to be 25 cents higher than the previous summer's average, but attributed 19 cents of that increase to high crude oil prices and that the transition from MTBE to ethanol would increase prices by "just a few pennies [72]."

The April 2006 Short-Term Energy Outlook attributed the expected price increase to several drivers [73]:

> Gasoline prices are expected to increase because of higher cost of crude oil compared with last year and the increase in production and distribution costs associated with Tier 2 gasoline and the phaseout of MTBE.

As with the transition from leaded to unleaded gasoline, identification of the true costs and impacts attributable to the transition from MTBE to ethanol is convoluted by the many factors that had simultaneously affecting the gasoline sector.

The removal of the RFG oxygen content requirement and state bans on MTBE were major drivers in the expanded use of ethanol. However, the EPAct of 2005 included an additional provision—the Renewable Fuels Standard (RFS) program—that would help to guarantee a major market for domestically-produced ethanol, and other biofuels.

2.2.5 Ethanol as a Gasoline Substitute

The initial version of the RFS was implemented in two separate final rules by the EPA. Due to the limited timeframe following the passage of the EPAct of 2005, the EPA implemented the standard as set forth in the EPAct of 2005 on December 30, 2005 for the year 2006 only. The agency then finalized the rule for 2007 and beyond on May 1, 2007. Shortly thereafter, the EISA of 2007 was passed, which substantially expanded the requirements of the program. The EPA is still in the process of finalizing the final rule, but has based the 2008 and 2009 volume requirements on the new requirements set forth by the EISA of 2007 [74]. Following the transition from MTBE to ethanol, the RFS has further spurred the growth of the ethanol industry. Figures 2-7 and 2-11 plot the increasing consumption of ethanol in recent decades.

Figures 2-9 and 2-11 approximate the quantity of ethanol used as an oxygenate additive in RFG. Although the RFG oxygen content requirement has been stricken from the CAA since May 2006, this approximation serves to illustrate the minimum amount of ethanol needed to replace the oxygen content previously supplied by MTBE. The approximation is based on the minimum volume percentage of ethanol needed to produce RFG with 2% oxygen by weight. An RFG with 5.7% ethanol by volume is needed to provide the oxygen content supplied with 11.2% MTBE by volume.[16] These differing volume percentage requirements explain the reduced volume of ethanol needed to produce RFG with 2% oxygen by weight, relative to MTBE.

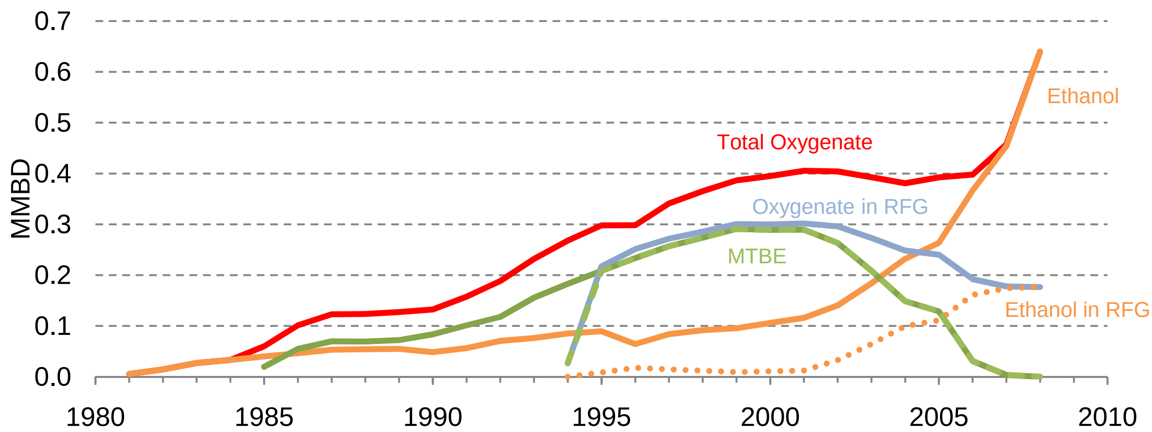


Figure 2-11. Ethanol has increasingly served as a substitute for gasoline, rather than simply a substitute for MTBE [42, 49-52].

In Figure 2-11, the gap between the data series 'Ethanol' and 'Ethanol in RFG' represents the volume of ethanol consumed as a substitute for gasoline. Although ethanol is an oxygen containing compound—an oxygenate—it is playing an ever increasing role as a direct substitute for crude-based gasoline.[17] Today, most gasoline suppliers blend RFG, and, increasingly, conventional gasoline (CG), with approximately 10% ethanol by volume (E10) for several reasons: (1) the Volumetric Ethanol Excise Tax Credit (VEETC) has encouraged E10 blends; (2) the vapor pressure of gasoline-ethanol blends

[16] See Table 2-3.

[17] It should be noted that a portion of the ethanol not used as a substitute for MTBE in RFG is actually consumed in (wintertime) oxyfuel areas. Although a significant share of ethanol demand might have been driven by the oxyfuel program in the early 1990s, as mentioned previously, the number of areas implementing the program has dropped substantially since its initial implementation in 1992. Data on the volume of ethanol consumed in oxyfuel areas have not been identified by the author.

peaks near the 5.7% blend point, dropping thereafter; and (3) the RFS program mandates ever increasing volumes of renewable fuels, which all obligated parties such as gasoline blenders, must meet annually. The future growth of the ethanol industry is examined in chapter 4.

2.2.6 Summary of Motor Gasoline Transitions

Although this overview of the motor gasoline sector does not account for all changes or modifications in gasoline composition over the last several decades, such as gasoline sulfur reductions (e.g., Tier 2 Gasoline Program), it has served to highlight several major transitions that have occurred and the implications associated with such transitions (discussed in further detail below). Table 2-4 summarizes the regulations that helped to drive transitions in the motor gasoline sector. These actions taken at the federal and state (primarily California) levels have led to significant modifications to gasoline over the last several decades. Figure 2-12 captures the overall growth in the motor gasoline sector along with several major transitional trends that have occurred: the transition from leaded to unleaded gasoline, the introduction of oxygenate additives in gasoline, the transition from MTBE to ethanol, and the expanded use of ethanol as a crude-based gasoline substitute.

Table 2-4. Federal (EPA) and California (CARB) motor gasoline regulations have aimed to eliminate lead additives, reduce fuel volatility, reduce air pollutants, and mandate oxygenates and renewable fuels content in gasoline.

Year	Agency	Regulation
1971	CA	Vapor Pressure 9.0 psi Max summer months
1974	US	Unleaded Gasoline required in service stations
1977	CA	Lead phase down
1980	US	Lead phase down
1989	US	Phase I Volatility Regulations – 10.5/9.5/9.0 psi max summertime
1992	CA	Vapor Pressure Phase I – 7.8 psi max summertime; part of California Reformulated Gasoline Program, Phase I (1992-1996)
1992	CA	Wintertime oxygen content – 1.8-2.2 wt %
1992	US	Phase II Volatility Regulations – 9.0/7.8 psi max summertime
1992	US	Federal Oxygenated Fuels (Oxyfuels) Program – 2.7 wt % min
1994	CA	Required all gasoline to be unleaded
1995	US	Federal Reformulated Gasoline, Phase I (1995-1999)
1996	US	Lead banned for highway fuel
1996	CA	California Reformulated Gasoline Program, Phase II
2000	US	Federal Reformulated Gasoline Program, Phase II
2006	US	Renewable Fuel Standard (EPAct 2005)
2006	US/CA	CA and Federal RFG oxygen content requirement removed (EPAct 2005)
2009	CA	Low Carbon Fuel Standard
2009	US	Renewable Fuel Standard 2 (EISA 2007)

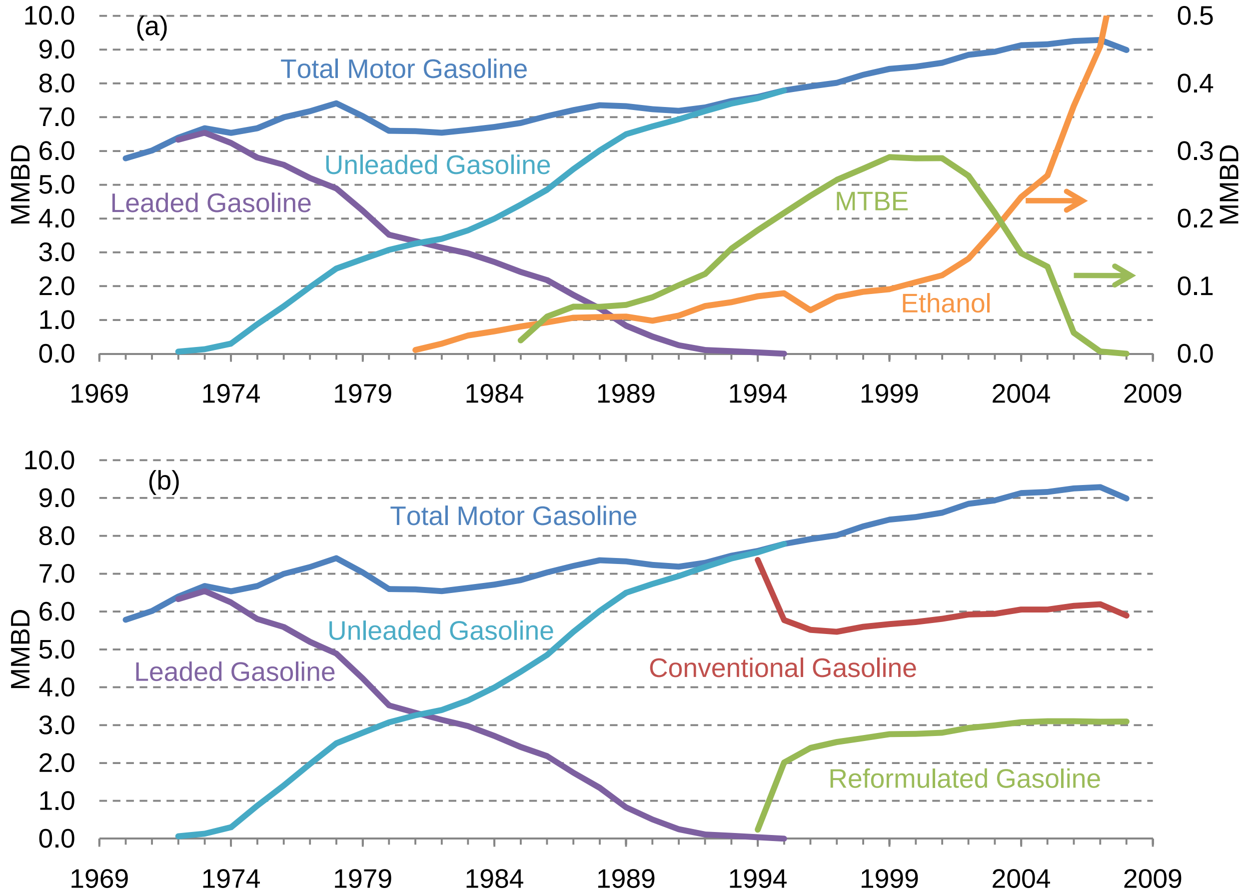


Figure 2-12. Trends in the US motor gasoline sector illustrate the numerous transitions that have occurred over the last several decades [29, 40-42, 49-52]. Both panels (a) and (b) illustrate the transition from leaded to unleaded gasoline. Panel (a) shows the growth in MTBE consumption and subsequent transition to ethanol, while panel (b) shows the introduction of RFG. Ethanol is included in the total motor gasoline consumption (the drop in total motor gasoline consumption in 2008 was not a result of increased ethanol consumption).

2.3 U.S. DISTILLATE SECTOR

The following discussion focuses on transitions in the U.S. distillate fuel oil (DFO) sector that have yielded significant reductions in sulfur content of finished distillate fuels (e.g. diesel) over the last two decades.[18] Distillate fuel oil, as defined in this thesis, includes distillate fuel oils no. 1, 2, and 4, which are differentiated by their boiling ranges.[19] These fuels are used primarily in diesel-powered equipment (i.e., diesel fuel) and heating oil applications (i.e., fuel oil). This classification of fuels also includes several alternative distillate fuels: biodiesel, renewable diesel, and synthetically-derived liquid fuels (e.g., biomass-, gas-, and coal-to liquids).

Sulfur is one of several heteroatoms found in limited quantities (<1%) in crude oil. The level of sulfur content varies greatly depending on the reservoir from which the crude is produced. Sweet crude oil is defined as petroleum that contains less than 0.5% sulfur by weight; petroleum containing higher levels of sulfur is defined as sour crude oil. Due to increasingly stringent regulations aimed at reducing sulfur content in distillate fuels (and gasoline), as discussed below, sweet crude oils are highly demanded by petroleum refiners, as they require less processing relative to sour crudes.

2.3.1 Introduction of LSD

The regulation of the concentration of sulfur in distillate fuels began on October 1, 1993 [75]. The EPA amended the CAA, Section 211, limiting the concentration of sulfur in motor vehicle (i.e., on-highway) diesel fuel to no more than 0.05% by weight (i.e., 500 parts per million (ppm) sulfur limit).[20] This amendment to the CAA was made

---

[18] Although there have been additional transitions in the composition of distillate fuels, sulfur stands as the most significant transition in this fuel sector, and is often compared to the removal of lead from gasoline, despite sulfur being a naturally-occurring element in crude oil.

[19] This definition is based on the DFO classification used by the EIA: "A general classification for one of the petroleum fractions produced in conventional distillation operations. It includes diesel fuels and fuel oils. Products known as No. 1, No. 2, and No. 4 diesel fuel are used in on-highway diesel engines, such as those in trucks and automobiles, as well as off-highway engines, such as those in railroad locomotives and agricultural machinery. Products known as No. 1, No. 2, and No. 4 fuel oils are used primarily for space heating and electric power generation." See http://tonto.eia.doe.gov/dnav/pet/TblDefs/pet_cons_psup_tbldef2.asp

[20] The regulation also required a minimum cetane index of 40 and maximum aromatics content of 35%.

in response to concerns expressed by the heavy-duty (HD) diesel engine manufacturers prior to the March 15, 1985 promulgation of particulate matter (PM) emission standards for HD diesel engines. The engine manufacturers were concerned that sulfur in diesel fuel, which can form sulfates in engine exhaust, could plug aftertreatment devices, which, at the time, were thought to be needed to meet the new PM standards. Sulfur also limits the effectiveness of the catalysts in aftertreatment devices. In addition, significant particulate sulfate emissions generated by high-sulfur fuel could make it challenging to meet the standards [76].

To ensure that sulfur in diesel fuel would not prevent the engine manufacturers from meeting the standards for 1994 and later model years, CAAA 1990 mandated refiners to reduce the sulfur content in on-highway diesel fuel. The mandate, which did not apply to off-highway diesel fuel and heating oil, required that distillates not meeting the standard be distinguished from low-sulfur diesel (i.e., 500 ppm sulfur limit) through the use of dyes [76, 77]. At the time, the low-sulfur diesel fuel (LSD) standard impacted approximately 47% of the DFO sector (refer to Figure 2-13) [78]. Figures 2-14 and 2-15 illustrate the introduction of LSD in the DFO sector. By 1994, LSD's share of the sector had increased to nearly 60%; in 2004, LSD comprised over 72% of the DFO supply in the U.S. [42].

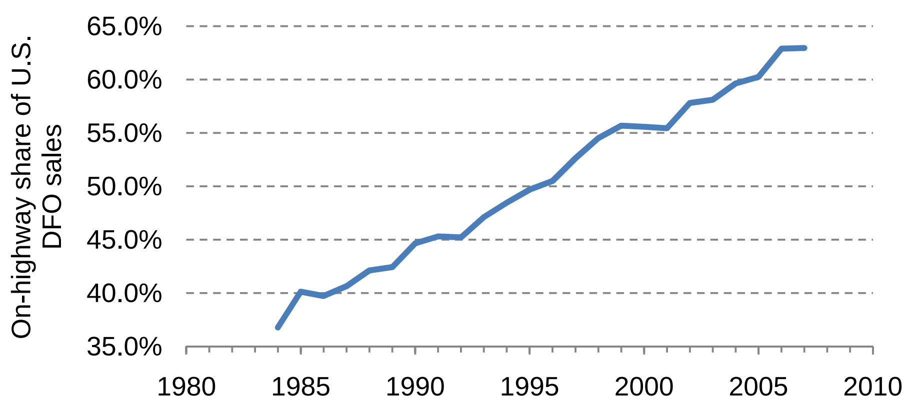


Figure 2-13. The on-highway diesel fuel market has increased its share of the DFO sector by nearly 30% since the 1980s, comprising nearly 65% of the sector in 2007 [78].

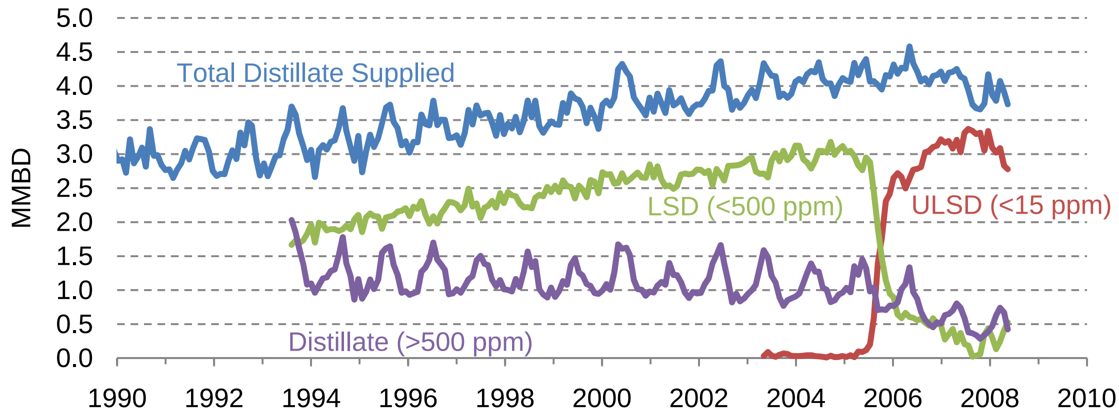


Figure 2-14. The distillate fuel oil (DFO) sector has undergone two transitions, i.e., reductions, in sulfur content (Note: data are monthly averages) [42]. The seasonal variation in the distillate supply is due to the increase in heating oil demand during the winter months.

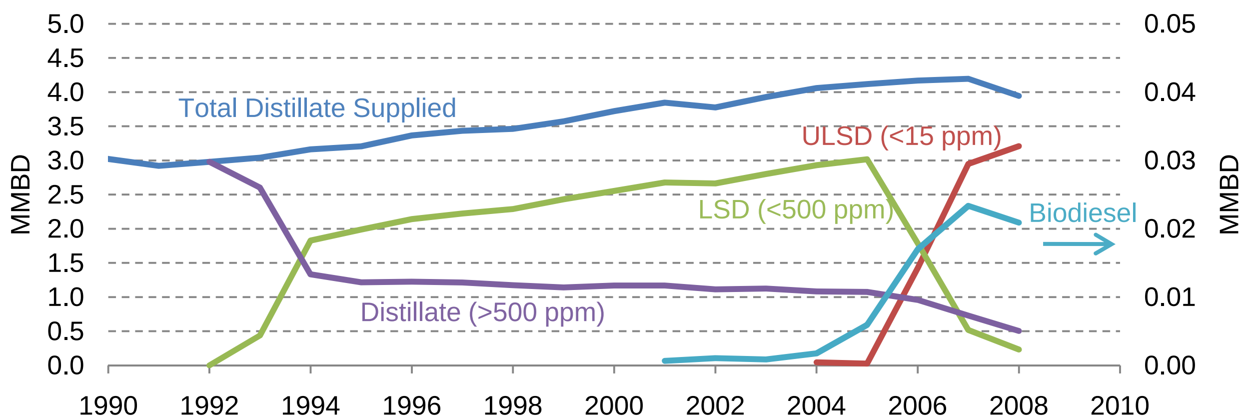


Figure 2-15. The DFO sector has seen little incorporation of renewable fuels. Biodiesel production has increased rapidly in recent years, yet supplies an insignificant share of the DFO sector (Note: data are annual averages) [18, 42].

2.3.2 Transition to ULSD

Just seven years after promulgating the LSD requirement, the EPA released its final rulemaking on HD Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements in December 2000, which, when implemented, would mandate another significant reduction in diesel fuel sulfur content. Once again, the need to limit sulfur in diesel fuel was forced by new emissions standards. The purpose of the HD Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements, otherwise known as the 2007 HD Highway Rule, is to significantly reduce emissions of NOx and PM from HD diesel engines and vehicles that use diesel fuel [79]. The EPA intended the rule to be technology forcing—by significantly limiting the primary criteria pollutants from diesel engines (i.e., NOx and PM), advanced emission control devices would become integral components of diesel engine systems [80].

During development of the rule, it was thought that diesel engines would need to be equipped with aftertreatment devices capable of driving PM and NOx emissions below the regulated levels. Advances in fuel system and in-cylinder combustion technologies alone could not make the deep emission reductions required by the rule. The primary technology proposed for controlling PM emissions was the diesel-particulate filter (DPF). Like the catalytic converters on gasoline-powered engines, which required the elimination of lead from gasoline, DPF performance is impacted by trace elements, including sulfur. Likewise, to control NOx emissions, engine manufacturers were looking to NOx adsorbers, whose catalysts are also rendered ineffective by sulfur. Therefore, to allow the manufacturers to develop and commercialize these emission control technologies, a further reduction in diesel fuel sulfur content was deemed necessary.

Like the lead phase down, the EPA justified the further reduction in sulfur content—to 0.0015% by weight (15 ppm sulfur limit)—based on the second criterion of Section 211(c)(1) of the CAA, which states that the EPA may mandate fuel controls if "the emission products of the fuel will significantly impair emissions control systems in general use or which would be in general use were the fuel control to be adopted." Since sulfur in diesel fuel exhaust "will significantly impair emissions control systems" thought to be necessary to meet the new emission standards, the EPA adopted the ultra-low-sulfur diesel fuel (ULSD) requirement (i.e., maximum 15 ppm sulfur). But, the EPA also justified this ruling on the first criterion, which allows for fuel controls if "the emission products of the fuel cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare." The EPA justified the sulfur reduction based on this criterion due to their belief that sulfate emissions contribute to PM pollution [75].

Originally, the 2007 Highway Rule required refiners and importers to produce ULSD starting June 1, 2006; the new fuel was required to be at terminals by July 15, 2006, and at retailers and wholesalers by September 1, 2006 [79]. However, as the ULSD transition approached, the diesel fuel industry raised concerns about their ability to supply ULSD throughout the entire distribution system by the required deadlines. The EPA responded by extending the deadlines for terminals and retailers by 45 days, pushing the implementation dates back to September 1 and October 15, 2006, respectively; some additional transition dates related to sulfur limits were extended as well [81].

The rule implemented a phase-in option, the "temporary compliance option," allowing refiners and importers to continue to supply up to 20% of the highway diesel fuel market with LSD through May 2010, with the remaining 80% meeting the new ULSD standard. Like the lead phase down, the EPA implemented an averaging, banking, and trading program, through which refineries could receive and trade credits for meeting certain ULSD production levels; the trading program will end in May 2010, coinciding with the conclusion of the aforementioned optional phase-in period. In addition, and once again mimicking the lead phase down, the rule includes hardship provisions for small refiners, defined as refiners with up to 1,500 corporate employees that had a crude oil capacity of 155,000 barrels or less per day in 1999 [79]. Each of these flexibility provisions and extensions was put in place to ease the transition to ULSD, which would become a major undertaking for the diesel fuel industry.

Figures 2-14 and 2-15 illustrate the introduction of ULSD in the DFO sector. When the new fuel was introduced, the highway diesel fuel market comprised 63% of the sector, over 15% more than at the time of the LSD introduction [78]. By 2007, the first full year that ULSD was in commerce, the fuel comprised 70% of the DFO supply in the U.S., leaving LSD with only a 12% share of the market. The next year, in 2008, ULSD made up 87%, leaving LSD with only 6% of the market [42]. The remainder of the market continues to be supplied with "standard" distillate having no limit on sulfur content. The phase-in option, allowing for 20% of highway diesel fuel to be supplied with LSD through May 2010, was clearly not utilized to its fullest extent by the fuel industry.[21]

2.3.3 Impacts of the Sulfur Reduction Transitions

As with transitions in the motor gasoline sector, the sulfur reduction transitions in the DFO sector would have significant ramifications for the refining industry, distribution and retail industry, and engine manufacturers.

The refining industry has several approaches for reducing the sulfur content in diesel fuel. According to the EIA, there exist 4 primary options for producing fuel with lower sulfur [76]:

- intensify the operation of new or existing catalytic hydrotreating units;
- increase production of low-sulfur distillates from catalytic hydrocracking units;
- limit diesel fuel blending to low-sulfur internal refinery streams; and
- import low-sulfur diesel.

The most viable options for reducing sulfur are through hydrotreating of distillate fuel or hydrocracking of heavy fuels. Increasing the amount of sulfur to be removed requires refiners to operate these units under more severe conditions (i.e., increased hydrogen volume, higher pressure and temperature, longer residence time). These

[21] By not utilizing the phase-in option to its fullest extent, the industry accelerated the transition to ULSD. This point is discussed further in section 2.4.3.

intensified operating conditions, in turn, shorten catalyst life and reduce unit capacity. Therefore, desulfurization capacity would need to be increased to produce lower-sulfur fuels at the required volumes.

Prior to the LSD transition, the EIA examined the potential impacts to the refining and distribution industry as a result of the new fuel control mandated by the EPA. Increased capital and operating expenses associated with the production of the new fuel, coupled with increased logistical demands placed on the distribution infrastructure in handling multiple distillate fuels, led the EIA to estimate that LSD would sell for a premium of 3 to 4 cents per gallon over other distillate fuels, namely, heating oil and other high-sulfur distillate fuels. At the time, refineries were producing a single distillate fuel that satisfied the requirements for both diesel fuel and heating oil, since the restrictions on these fuels were so similar. With a new sulfur control applied to on-highway diesel fuel, refiners would be faced with the decision of whether to segregate this new fuel from other distillates; segregation of fuel streams could reduce capital and operating expenses associated with expanded desulfurization capacity, yet these cost reductions could be more than offset by the increased costs associated with the additional infrastructure needed to handle separate product streams within the refinery. The EIA report suggested that due to these cost burdens, segregation of fuels between different refineries was quite possible. Refiners lacking the resources needed to produce LSD could focus on producing only high-sulfur distillates for the off-highway and heating oil markets, leaving the on-highway LSD market to larger refineries with spare desulfurization capacity and/or greater resources to expand this capacity [76]. Overall investments made by the fuels industry as a result of the LSD transition were not identified by the author.

Aside from impacts to the refining and distribution industry, the end use segment of the supply chain also experienced impacts from the transition to LSD. Although the engine manufacturers were advocates of sulfur reductions, which were needed to meet the new PM standards, it turned out that this modification of diesel fuel did not simply limit sulfur content. The intensified desulfurization processes needed to produce LSD reduced the content of aromatics and other high-molecular weight hydrocarbons. The reduction of these hydrocarbon compounds had two impacts on engine operation. First, these hydrocarbon compounds serve as natural lubricity agents critical to the operation of diesel engine fuel systems (e.g., fuel pumps and injector components). The new LSD, with its reduced content of these lubricating compounds, caused wear issues in diesel engine fuel systems—primarily in fuel pumps. Second, this altered composition of LSD caused fuel system seals to lose their set. When these seals, made with various rubbers and elastomers (e.g., nitrile), are initially exposed to high-sulfur diesel, they swell to a certain set; when these seals are later exposed to LSD, the seal swell will reduce. During the transition to LSD, this characteristic of fuel system seals created widespread cases of leaking fuel pumps. Diesel engines that went into operation following the introduction of LSD did not experience this problem; since the seals were never exposed to the high-sulfur diesel, their set was established with the new fuel. These lubricity and seal integrity issues manifested themselves from 1993 to 1994 [82, 83]. It is not clear why the industry did not fully anticipate these problems and attempt to limit their impacts.

Following the issuance of the 2007 Highway Rule final rulemaking, the EIA conducted a thorough analysis of the costs and impacts associated with the transition to ULSD [79]. The analysis estimated that refiners would be burdened with new investments ranging from $6.3 to $9.3 billion through 2011. The study compiled a range of estimates made by various industry groups, agencies, and laboratories. The estimated refinery capital investments ranged anywhere from $3.0 to $13.2 billion (1999 dollars), illustrating the significant uncertainties associated with the costs of this mandated transition.[22] Some of the uncertainties, as identified by the EIA, included:

- rate of development of refinery and pipeline testing technology;

[22] The EPA estimated that the refining industry would face $5.3 billion in capital investments in the 2007 Highway Rule RIA. Due to the rule's focus on diesel engine emissions reductions, and not simply diesel fuel sulfur control, a detailed review of the RIA and cost-benefit analysis is not provided. The 2007 Highway Rule RIA can be downloaded from the following EPA webpage: http://www.epa.gov/otaq/highway-diesel/regs/2007-heavy-duty-highway.htm

- supply of personnel, thick-walled reactors, and reciprocating compressors (for the expansion of desulfurization capacity);
- behavior of the new fuel in the pipeline infrastructure; and
- cost recovery in the pipeline industry.

The cost estimates mentioned above did not include impacts to the distribution industry. Due to the optional phase-in provision, the distribution industry would be responsible for simultaneously handling LSD, ULSD, and high-sulfur distillate fuel through 2010. This flexibility provision, although helpful to some refiners, would place a significant burden on the distribution industry. Capital investments in infrastructure and additional operating costs would be needed to handle multiple products. In addition, the distribution industry had expressed concerns about contamination of ULSD with higher-sulfur distillates resulting in significant volumes of ULSD being downgraded to a higher-sulfur fuel (with lower market value).

Support for the new ULSD standard ranged from outright opposition to full-fledged support. The National Petrochemical and Refiners Association (NPRA), the API, the Society of Independent Gasoline Marketers of America (SIGMA), and the National Association of Convenience Stores (NACS) filed suit against the EPA, expressing concerns about the possibility of inadequate supply. In addition, the 4 industry groups opposed the phase-in option due to the costs associated with storing multiple fuels. In contrast, a coalition of environmental, manufacturing, regulatory (e.g., state and local regulators striving to meet NAAQS attainment), and trucking groups strongly supported the rule [79].

Despite these burdens placed on the refining, distribution, and retail industry, and the strong opposition from many industry groups, the on-highway ULSD fuel transition seems to have been a success with minimal, isolated instances of supply disruptions and price aberrations [84, 85]. By October 2006, an EIA senior analyst explained, "Our understanding is that the transition is essentially complete [85]." Relative to 2005 prices, the national average (retail) diesel price did not exhibit any noteworthy increases during

2006 when the EPA deadlines associated with the ULSD transition were reached (see Figure 2-16). Again, these national average prices may conceal evidence of localized price volatility.

It is interesting to note that the ULSD transition occurred during the same time frame as the transition from MTBE to ethanol in motor gasoline. The fuel industry successfully managed two major fuel transitions more or less simultaneously in the two largest markets of the U.S. liquid fuels sector. Despite initial resistance from industry, these transitions occurred in an efficient and timely manner without any noticeable increase in fuel prices.

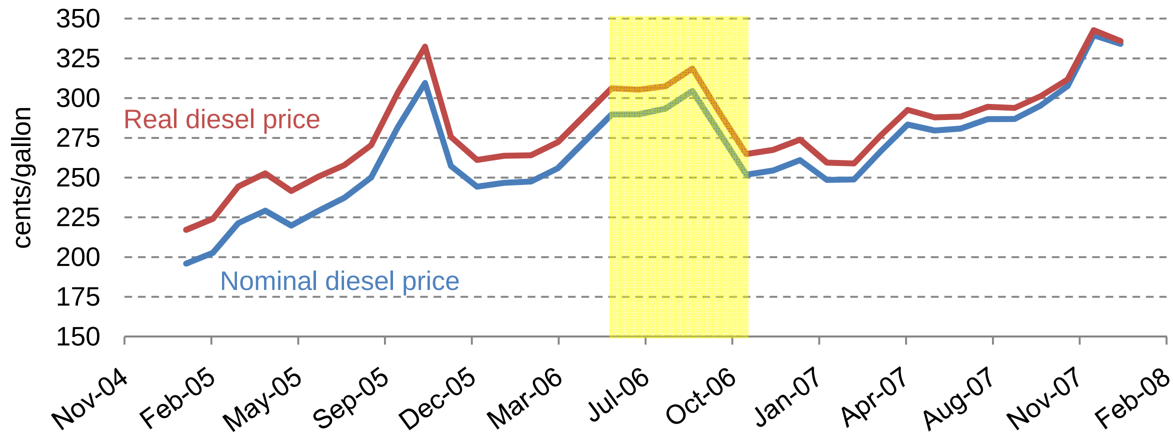


Figure 2-16. National average retail diesel prices (real and nominal) during the ULSD transition (shaded box) followed a slightly longer seasonal increase than the prior year [67].

When the transition occurred, and ULSD was introduced to the market, some engine operators experienced fuel leaks due to seal swell degradation. The further reduction of sulfur, requiring intensification of the desulfurization processes, further reduced the content of aromatics and other high-molecular weight hydrocarbons. Engines that switched from operating on LSD, or other higher-sulfur distillates, to the new ULSD experienced a repeat of the fuel-leak problems that occurred in 1993 and 1994 during the LSD transition. Fortunately, the industry did anticipate the accompanying reduction in lubricating properties and took the necessary precautions by adding lubrication additives to the finished ULSD product [82]. The EPA even included this additional cost burden in their RIA of the 2007 Highway Rule, estimating a cost of 0.2 cents per gallon for lubricity additives in ULSD [75, 79].

For the fledgling biodiesel industry, the introduction of ULSD was embraced as a marketing opportunity. Although the biodiesel industry had been growing rapidly in recent years, it was supplying a rather insignificant share of the DFO sector. Prior to the ULSD transition, in 2005, the biodiesel industry's share of the DFO sector stood at less than one-quarter of one percent (see Figure 2-15). Due to the reduced lubricity in ULSD, and corresponding need to recover the lubricity with additives, the biodiesel industry attempted to push its product as a solution to this problem. According to results compiled by the National Biodiesel Board (NBB), low-level blends of biodiesel can significantly improve the lubricity of diesel fuels. Blending low-sulfur diesel fuels with as little as 2% biodiesel restores the lubricating properties exhibited by higher-sulfur diesels [86]. Although the industry may have benefited from this new market opportunity, biodiesel continues to supply an insignificant share of the DFO sector.

Interestingly, as a result of the diesel fuel sulfur reductions (and gasoline sulfur restrictions), the sulfur production capacity of U.S. refineries has expanded significantly over the last two decades. Figure 2-17 shows the annual sulfur production capacity of U.S. refineries in 1,000 short tons per day. This co-product of the refining industry has impacted traditional sulfur markets. In 2000, it was reported that the last domestic Frasch sulfur mine closed, ending discretionary sulfur production in the U.S. As a result, domestic users of sulfur (e.g., fertilizer production) must now rely heavily on the expanded production of recovered elemental sulfur from petroleum refineries. A similar trend has occurred globally, as other nations and regions have placed similar limits on sulfur content in liquid fuels [87]. Depending solely on co-product sulfur, rather than direct sulfur sources (i.e., mining), can leave sulfur users susceptible. For example, in 2005, total U.S. sulfur production was down 5% from the previous year due to the active hurricane season in the Gulf Coast regions, which resulted in major refinery shutdowns

[88]. Any disruptions to refining activities can ultimately limit sulfur availability. Therefore, if petroleum products demand were to be significantly reduced in the future, through increased use of alternative fuels, for example, the sulfur industry may need to return to traditional reserves (i.e., mined sulfur) to maintain supplies.

In this example, the petroleum industry was able to establish a market for its co-product sulfur. Similarly, the biofuels industry faces the need to identify markets for the co-products of biofuel production processes. For example, the corn ethanol industry currently produces significant quantities of distiller's dried grains with solubles (DDGS). The increased production of this co-product has caused ethanol producers to aggressively pursue new markets in the livestock feed industry [89]. Aside from being an important economic component of corn ethanol production, the treatment of the DDGS co-product can influence results of corn ethanol lifecycle analyses (e.g., lifecycle GHG emissions) [90]. The inability to establish robust markets for biofuel co-products could become a major barrier in a biofuels transition.[23]

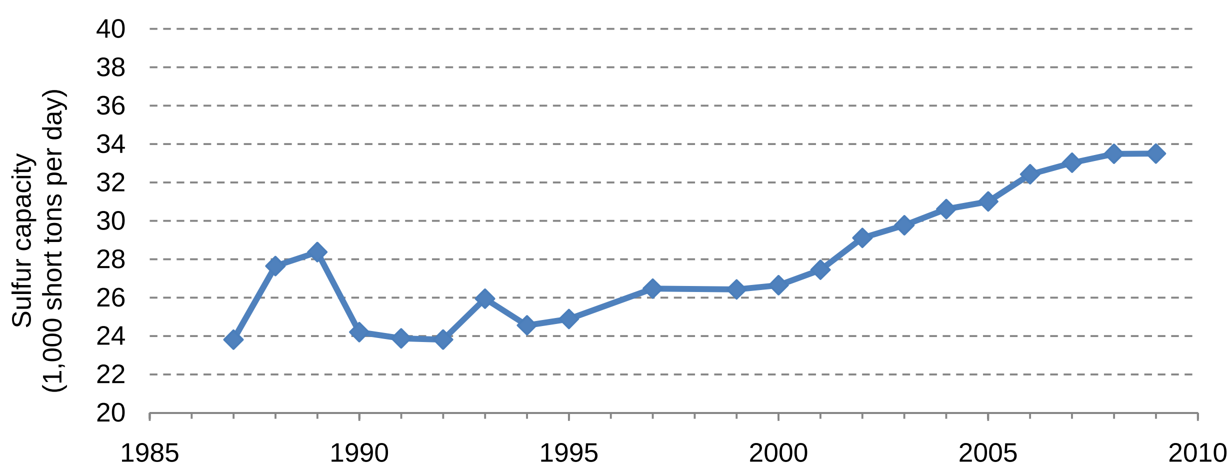


Figure 2-17. U.S. refinery sulfur production capacity has increased due to fuel sulfur content restrictions [91].

[23] Barriers to a biofuels transition are discussed in chapter 4. However, biofuel feedstock issues, including co-products, were omitted from the scope of this thesis.

2.4 Implications of Transitions

A concise summary of major transitions in the U.S. liquid fuels sector is presented in Tables 2-5 and 2-6. Transitions in the motor gasoline and DFO sectors are summarized according to their time frame (and approximate duration), key drivers and regulations, and impacts to the fuel supply chain infrastructure. The infrastructure changes in each segment of the fuel supply chain are differentiated according to major (M), minor (m), and negligible (-) impacts. This categorization is discussed further in section 2.4.2. The motor gasoline sector includes the transition from leaded to unleaded gasoline, the use of high octane hydrocarbons in gasoline, the mandated use of oxygenate additives in gasoline, the transition from MTBE to ethanol as the predominant oxygenate additive in gasoline, and the ongoing growth of ethanol as a direct substitute for crude-based gasoline. The DFO sector includes the two reductions in sulfur content in diesel fuel: the introduction of LSD, and the introduction of and transition to ULSD.

Defining the time frame and duration of a given transition is not so straight forward. Since many of these transitions involve a growth phase, or market penetration, followed by a phase down, or market reduction/elimination, the definition of the transition duration is debatable. For example, the introduction of oxygenate additives in gasoline covers the significantly expanded use of oxygenates due to state and federal mandates on gasoline composition. Oxygenates were being used as early as the 1960s; they continue to be used today. Yet the time frame for this transition is defined here as the late 1980s through 2006. The expanded use of oxygenates, through mandates, did not begin until the late 1980s when some states implemented wintertime oxygenated fuels programs. The majority of mandated use of oxygenates ended in 2006 when the EPA amended the CAA to eliminate the oxygenate requirement from the RFG program. Oxygenates are still used in RFG, but are no longer mandated; the continued use of ethanol in RFG is a strategic decision made by gasoline suppliers. The Oxyfuel program is still implemented in some areas, but its extent has diminished significantly since being established on a federal level in 1992. Overall, the expanded use of oxygenates to satisfy gasoline composition requirements is defined in this thesis as spanning approximately two decades from the late 1980s to the late 2000s. However, the transition time to introduce oxygenates was much shorter, but is difficult to define.

These historical transitions represent the uncertainty and diversity of future transition pathways in the liquid fuels sector (e.g., a transition to biofuels), and raise the following questions when looking forward:

- What are the key takeaways and lessons learned from these case studies?
- Are there any generalizable trends or patterns that emerge from these transitions?
- As we look to the future in this sector, with new regulations that mandate the increased use of renewable fuels, what might we expect, or how can we better anticipate the varied implications of this ongoing biofuels transition?
- How can we apply lessons and experiences from past transitions moving forward?
- How do these findings help to identify barriers that may exist in current policies, market conditions (i.e., economic factors), the structure of today's industries, or the state of technology, etc, which could impede a transition to biofuels?

Table 2-5. Transitions in the motor gasoline sector are characterized by their timing, drivers, and infrastructure implications. Infrastructure changes are differentiated by major (M), minor (m), and negligible (-) impacts.

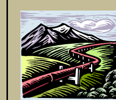
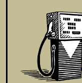
Sector	Transition	Time Period; Duration	Drivers; Regulations	Infrastructure Implications				
				Production 	Refining 	Distribution 	Retail 	End use 
Motor Gasoline	Leaded to Unleaded Gasoline	1974 ~ 1995 ~20 years	Policy; Lead additives impair catalytic converters, Toxicity; CAA 1970, CAAA 1990	-	m	m	M	M
	High Octane Hydrocarbons (Butane, Aromatics) in Gasoline	1980 ~ 1990 (span) 1~2 years	Market and Policy Initially used by refiners to recover octane in gasoline; Volatility regulations and RFG program put in place; State programs, CAAA 1990	-	m	-	-	-
	Oxygenates in Gasoline	1980s ~ 2006 (variable)	Market and Policy; Initially used by refiners to boost octane in unleaded; RFG and Oxygenated Fuels Programs; State programs, CAAA 1990	m	m	m	-	-
	MTBE to Ethanol as Gasoline Oxygenate	1999 ~ 2006 <10 years	Policy and Legal; MTBE use leads to drinking water contamination; State bans on MTBE, Refiner liability concerns	M	M	m	-	-
	Ethanol as a Gasoline Substitute (≤ E10)	1980s ~ 2010 20~30 years	Policy (and Market); Renewable Fuel Standard Program; EPAct 2005, EISA 2007	M	M	M	-	-
	Ethanol as a Gasoline Substitute (≥ E10)	2010 ~ ? >20 years (?)	Policy (and Market?); Renewable Fuel Standard Program; EISA 2007	M	M	M	M	M

Table 2-6. Transitions in the DFO sector are characterized by their timing, drivers, and infrastructure implications. Infrastructure changes are differentiated by major (M), minor (m), and negligible (-) impacts.

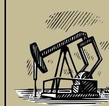
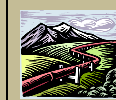
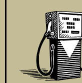
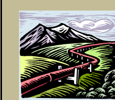
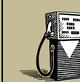
Sector	Transition	Time Period; Duration	Drivers; Regulations	Infrastructure Implications				
				Production 	Refining 	Distribution 	Retail 	End use 
Distillate Fuel Oil (DFO)	Low-Sulfur Diesel (<500ppm)	1993~ 1994 ~2 years intro 1993~2006 >10 years total	Policy; PM standards require fuel sulfur reduction; CAAA 1990		m	m	-	m
	Ultra-Low-Sulfur Diesel (<15ppm)	2006~2007 ~ 1 year	Policy; PM and NOx standards; Sulfur impairs diesel emission control devices; Sulfate emissions contribute to PM; 2007 HD Highway Rule (CAA)		m	m	-	m

Table 2-7. The duration of fuel transitions has varied with the extent of infrastructure implications. Infrastructure changes are differentiated by major (M), minor (m), and negligible (-) impacts. Transitions are ordered (approximately) from shortest to longest duration. Refer to Tables 2-5 and 2-6 for a listing of the drivers and regulations of transitions.

Sector	Transition	Time Period; Duration	Infrastructure Implications				
			Production 	Refining 	Distribution 	Retail 	End use 
Motor Gasoline	High Octane Hydrocarbons (Butane, Aromatics) in Gasoline	1980 ~ 1990 (span) 1~2 years (?)	-	m	-	-	-
DFO	Ultra-Low-Sulfur Diesel (<15ppm)	2006~2007 ~1 year	-	m	m	-	m
DFO	Low-Sulfur Diesel (<500ppm)	1993~ 1995 ~2 years	-	m	m	-	m
Motor Gasoline	Oxygenates in Gasoline	1980s ~ 2006 (variable)	m	m	m	-	-
Motor Gasoline	MTBE to Ethanol as Gasoline Oxygenate	1999 ~ 2006 <10 years	M	M	m	-	-
Motor Gasoline	Leaded to Unleaded Gasoline	1974 ~ 1995 ~20 years	-	m	m	M	M
Motor Gasoline	Ethanol as a Gasoline Substitute (≤ E10)	1980s ~ 2010 20~30 years	M	M	M	-	-
Motor Gasoline	Ethanol as a Gasoline Substitute (≥ E10)	2010 ~ ? >20 years (?)	M	M	M	M	M

As an example, Sperling and Dill provided several explanations for the successful transition to unleaded gasoline, which can be summarized as follows [29]:

- New technologies are bound to experience problems out of the gate. In order to avoid scrutiny, new fuels and vehicles must exhibit high levels of quality.
- Government must be certain it can enforce standards should it choose to ignore the market. If a large number of players are involved in a particular segment of the market, the ability to enforce standards is diminished. Misfueling was identified as the major failing of the transition to unleaded gasoline, and can be attributed to the inability to monitor the large number of vehicle owners.
- Widespread support. The national commitment to air quality improvements during the 1970s bolstered the adoption of unleaded gasoline.
- Concentration of authority and responsibility in one organization allows for the effective development of strategies and coordination of activities. In the transition to unleaded gasoline, the EPA was the sole federal agency coordinating the promulgation of rules and regulations affecting all sectors of the industry.
- Reduction of uncertainty and risk in the marketplace allows for a stable environment for investment and participation by industry and consumers. Cooperation between government and industry to standardize technologies, use incentives and mandates to encourage fuel production, and follow established timetables all contributed to the successful transition to unleaded gasoline.

As mentioned at the beginning of this chapter, Sperling and Dill suggested that the government-coordinated transition to unleaded gasoline serves as a "model for the United States and other countries for the introduction of nonpetroleum fuels." They further suggested that the transition "faced the same type of obstacles as would any other new fuel, dissimilar to petroleum, such as alcohols, gaseous hydrocarbons, and hydrogen." This point could readily be dismissed. None of the major transitions that have occurred in the liquid fuels sector, as summarized in Tables 2-5 and 2-6, have involved a fuel substitution, or interfuel substitution. Stated alternatively, it can be argued that these transitions have been nothing more than fuel modifications of the same base fuels (i.e., crude-based gasoline and distillates) used predominantly to power the same base engine technologies (i.e., spark- and compression-ignition internal combustion engines). Interestingly, in a book published the same year as Sperling and Dill's aforementioned journal article on the unleaded gasoline transition, Sperling seems to concur with this alternative view [92]:

> [I]nterfuel substitution has in fact resulted in substantial reductions in petroleum consumption in industrial, residential, commercial, and electric utility activities. Coal, natural gas, nuclear power, and more decentralized sources such as solar heat, wind power, geothermal energy, and small hydroelectric plants have supplanted petroleum in many activities, but not in transportation. In the transportation sector there has been practically no interfuel substitution (p. 19).

Each transition in a given sector (e.g., motor gasoline) has caused an incremental change of the same technology or base fuel. Therefore, the transitions that have occurred in these sectors (i.e., motor gasoline or DFO) could be viewed as a continuum of change, or ongoing evolution, of a given fuel technology.

Exceptions to this fuel modification viewpoint could be the introduction of oxygenate additives in gasoline and the transition from MTBE to ethanol that ensued. MTBE, derived from natural gas and petroleum, allowed for a portion of the motor gasoline feedstock supply to shift from petroleum to natural gas. Ethanol, derived mostly from corn starch, allows for a shift from petroleum to agricultural commodities (and their associated inputs). For these oxygenate transitions, the feedstock shifts have been minimal at best. Moving forward, as greater volumes of biofuels are incorporated into the liquid fuels sectors, this shift away from petroleum feedstocks could become substantial, edging towards a true fuel substitution. As will be shown in the chapter 4, this shift is already causing a reduction in crude-based gasoline in the motor gasoline sector (i.e., "peak gasoline") [93].

This dearth of fuel substitutions should not nullify the lessons and findings from historical transitions in the sector. The liquid fuels sector is comprised of a massive, well-established network of industries and accompanying infrastructures, supported by and integrated with regulations, practices, and institutions. A transition to biofuels in the liquid fuels sector will not occur independently or in isolation from this system. Understanding how previous transitions progressed and altered this established sector is critical to understand any future transitions. But, acknowledging the limitations of such an analysis is just as important when considering the implications of an interfuel substitution in the liquid fuels sector.

The following key takeaways were derived from the review of historical transitions in the U.S. liquid fuels sector:

- transitions are common;
- transitions have variable infrastructure implications;
- transitions exhibit variable time scales;
- transitions are better understood through an integrated view of vehicles and fuels;
- transitions are analyzed differently when system boundaries are expanded;
- transitions can have unintended consequences.

This list is not necessarily generalizable to other technological transitions, as it is based on a limited review of transitions in the liquid fuels sector. These takeaways are discussed below and analyzed in the context of a biofuels transition.

2.4.1 Transitions are common

Dynamic technological systems (e.g., the transportation sector) commonly undergo change [94-96]. The liquid fuels sector, a complex technological system, is also subject to change. Through our review of major transitions in the motor gasoline and DFO sectors, it becomes evident that change is quite common. Technological systems are not static; they are altered, by human society, to address new problems, to become more efficient, and to improve the delivery of services. In the motor gasoline sector, lead additives were adopted to allow for the development of more powerful engines (with higher compression ratios). In the drive to adopt this technology, the impacts of introducing this additive into gasoline were not fully investigated or anticipated, or were simply ignored [97]. As society came to realize the detrimental impacts of lead in the environment (i.e., human health effects), approximately 20 years were needed to eliminate this additive from gasoline (it still finds favor in some applications to this day). In the ensuing drive to recover octane in gasoline, refiners modified their operations to increase the content of high-octane hydrocarbons. This fuel modification, in turn, caused new problems: the higher-volatility fuel resulted in increased VOC emissions, and increased aromatics content resulted in greater toxics emissions. New regulations were put in place, leading to more change. Oxygenates were introduced to reduce air emissions, with MTBE rising as the preferred additive. This time, the problems did not manifest as air emissions, but rather as water pollution.

Moving forward, energy security and climate change serve as drivers behind the search for alternatives to petroleum-derived liquid fuels, such as biofuels. As biofuels become a ubiquitous component of the liquid fuels sector, what aspects of this technology need to be addressed? In the push to adopt biofuels, what warnings and concerns are being overlooked or neglected? Although society cannot fully predict the outcomes of a transition to biofuels, the path forward may be better navigated through an enhanced understanding of historical transitions.

2.4.2 Transitions have variable infrastructure implications

Tables 2-5 and 2-6 summarize the extent of infrastructure implications associated with fuel transitions in the motor gasoline and DFO sectors, respectively. For each segment of the fuel supply chain, changes to the infrastructure are differentiated by major (M), minor (m), and negligible (-) impacts.[24] Although infrastructure impacts cannot be

[24] The categorization of infrastructure impacts is based solely on the information presented in sections 2.2 and 2.3 for the motor gasoline and DFO sectors, respectively.

fully represented with these simple, qualitative indications, they do allow for quick comparisons of fuel transitions according to the number of segments impacted, and the extent of those impacts.

For example, the burden of using high-octane hydrocarbons to recover octane rating in gasoline was isolated to the refining industry. Crude-oil production, distribution, retail, and end use were not directly affected by this fuel modification implemented by refiners. Since the fuel modifications did not require an expansion of fuel refining capacity, the impact to refining is categorized as minor (m). On the other hand, the transition to ethanol as a gasoline substitute (≤ E10) has had major impacts on several segments of the fuel supply chain. Ethanol, being produced primarily from grain corn, has shifted a portion of motor gasoline feedstock away from crude oil. Fuel production capacity has expanded with the construction of ethanol production facilities, i.e. corn distilleries. The distribution of ethanol has relied on the development of a "virtual pipeline," comprised of rail, barge, and truck distribution networks. The impacts to each of these segments (production, refining, and distribution) are considered to be major (M). However, ethanol is still consumed primarily in the form of low-level blends (≤ E10). Therefore, impacts to the retail and end use segments have been negligible (-).

Table 2-7 presents the same information as Tables 2-5 and 2-6, but orders the transitions according to approximate durations, from shortest to longest. Interestingly, the durations align well with the number of segments impacted in the fuel supply chain infrastructure, and the extent of those impacts (i.e., major, minor, or negligible). The variability of time scales exhibited by transitions is discussed further in the next section.

2.4.3 Transitions exhibit variable time scales

The durations listed in Table 2-7 illustrate the variability in time scales of transitions. The transition to unleaded gasoline took approximately 20 years, with lead additives finally being eliminated from on-highway gasoline in 1995. At the other end of the spectrum, the introduction of ULSD required only one year (approximately).

Looking forward, the continued transition to ethanol as a gasoline substitute (≥ E10)[25] could easily surpass these historical transition durations.

The transition to unleaded gasoline had implications throughout most of the supply chain, and was the first major transition in the motor gasoline sector. Refiners needed to alter operations to recover the octane that had been provided by lead additives. During the transition, when both leaded and unleaded gasolines were available, the distribution and retail network had to adapt to supply multiple fuels. Although unleaded gasoline was compatible with the existing infrastructure (e.g., pipelines), the distribution and retail network had to alter operations and add storage capacity in order to handle both unleaded and leaded gasolines throughout the transition. Vehicle manufacturers altered engine designs with lower compression ratios due to the anticipated reduction in octane rating of gasoline. In Tables 2-5 and 2-7, the impacts to the refining, distribution, retail, and end use segments are indicated as minor (m), minor (m), major (M), and major (M), respectively. In addition, the transition impacted the entire motor gasoline supply, not just specific segments, as seen with the use of oxygenate additives in gasoline. Oxygenate additives were used in the formulation of RFG and wintertime oxyfuel. These fuels were (and are still) supplied to specific geographic locations, and overwhelmingly to large demand centers, like the Northeast states and California. People have argued that the transition to unleaded gasoline in the U.S. could have occurred at a more accelerated pace [37, 38]. Many nations, particularly in the EU, completed the transition to unleaded gasoline in less than a decade [38]. However, the U.S. was the first nation to initiate a transition to unleaded gasoline.

On the other hand, the sulfur reduction transitions in the DFO sector occurred rapidly. These transitions impacted a majority of the DFO sector: LSD comprised over 72% of the DFO supply at its peak in 2004, while ULSD made up 87% of the supply in 2008. With the reduction of sulfur, no major performance-enhancing properties of the fuel were altered (e.g., cetane). This factor stands in sharp contrast to the important role

[25] The continued transition to ethanol as a gasoline substitute (≥ E10) was added to the last row of Table 2-5 (and 2-7) as a "forward-looking" transition, which is explored further in chapter 4.

that lead additives played in the gasoline market (i.e., to boost octane). Refiners were required to reduce sulfur content, but did not need to recover any critical combustion-performance properties. When the market realized that the desulfurization processes reduced the content of aromatics and higher-molecular weight hydrocarbons, small quantities of lubricity additives were simply added to the fuel to recover the lubricating properties of these hydrocarbon compounds. In the case of the ULSD transition, the distribution and retail network had expressed concerns about the 80/20 phase-in option, allowing ULSD and LSD to coexist in the market through 2010. By accelerating the phase-in of ULSD, and accompanying phase-out of LSD, the market has limited the impacts of handling multiple products. If the refiners are capable of producing enough of the new fuel (i.e., ULSD), the distribution and retail industry faces fewer obstacles and will more efficiently deliver the new fuel to the consumer. In Tables 2-6 and 2-7, the impacts to the refining, distribution, and end use segments are all indicated as minor (m). The overall size of the DFO sector may have played a role in the rate of these sulfur transitions as well. The DFO sector is less than one half the size of the motor gasoline sector: in 2008, an average of approximately 9 MMBD of motor gasoline was consumed, compared to approximately 4 MMBD of distillates. Even during the transition to unleaded gasoline, the size of the motor gasoline sector grew from approximately 6.5 to 7.5 MMBD.

The ethanol industry has grown at a rapid rate over the last decade as demand for this alcohol has been driven by several factors, namely, the biofuels mandates, tax credits, and elimination of MTBE from the gasoline supply. The future growth of this industry could be dependent upon a number of limiting factors. From the production side, previous transitions in the liquid fuels sector provide little insight. These transitions did not result in any significant shifts away from petroleum feedstocks. The production of ethanol, and other biofuels, will clearly be limited by the availability of biomass feedstocks. In the refining segment, biorefinery (e.g., ethanol distilleries) capacity is a limiting factor. Previous transitions have not been hampered by overall limits in fuel production capacity, only in the capacity of specific processes within refineries. For example, during the sulfur reduction transitions, refineries were not limited by overall fuel production capacity, but rather by the capacity of desulfurization units in the existing refining capacity. The growth in biofuels production capacity is not simply limited by how quickly plants can be built and commissioned, but by the development of new technologies. The biofuels mandates require that specific types of biofuels be produced, e.g., cellulosic ethanol, even as the technologies have yet to be fully developed on a commercial scale. Therefore, the production aspect will be limited by both technology development and capacity growth. The distribution and retail network will also be forced to adapt. Currently, ethanol is not moved through the vast petroleum pipeline infrastructure due to ethanol's affinity for water and associated corrosive characteristics. As mentioned earlier, the distribution industry has expanded and optimized the use of existing train, barge, and trucking systems to develop a "virtual pipeline" for moving ethanol [71]. The efficacy of this virtual pipeline to distribute ethanol to the motor gasoline market could be diminished as the volume of ethanol expands in the coming years. Some pipeline operators are looking to adapt. For example, Kinder Morgan is shipping commercial volumes of ethanol through existing pipelines in Florida [98, 99], and announced plans to distribute biodiesel blends through pipelines in the Southeast states [100]. Magellan Midstream Partners and POET Energy are conducting a feasibility study of building a dedicated ethanol pipeline extending from South Dakota through the major ethanol producing regions of the corn belt, and finally to the Northeast states for delivery [101]. At the retail level, most conventional and reformulated gasoline is currently blended with up to 10% ethanol, which does not require new equipment (e.g., dispensers, tanks, etc). But, as the mandated volumes increase, retailers will be required to move greater volumes of ethanol. Currently, the only option available to retailers, other than E10, is E85. The rate at which retailers expand their offering of E85, which requires the use of ethanol-compatible equipment (e.g., dispensers, tanks, etc), will be a major limiting factor to this transition.[26] Finally, the end use segment provides

[26] As will be discussed in chapter 4, the nation's motor gasoline pool could reach a 10% limit in the next few years, requiring any increased consumption of ethanol to come in the form of E85.

challenges as well. With the need to expand E85 offerings at the retail level, retailers will need a market for this fuel. To safely use this fuel without causing engine damage, consumers must own a flex-fuel vehicle (FFV). The fleet of FFVs must grow rapidly in order to consume the higher ethanol blends that must be pushed through the market. In Tables 2-5 and 2-7, the impacts to the production, refining, distribution, retail, and end use segments are all indicated as major (M). Each of these impacts throughout the fuel supply chain could influence the rate at which the ethanol industry expands in the future.

This discussion, although focused on ethanol, illustrates that the characteristics of a particular biofuel, and the impacts that the fuel has on different segments of the fuel supply chain, influences the rate at which the fuel could penetrate the liquid fuels sector. The time scale of a biofuels transition will be influenced by a number of factors, and is dependent on the types of biofuels that will be produced in the future. The barriers to a biofuels transition are explored further in chapter 4.

2.4.4 Integrated view of vehicles and fuels

These historical transitions highlight the importance of developing an integrated view of vehicles and fuels. When considering the impacts of fuel transitions, those that impact the end use segment (i.e., vehicles) are at a significant disadvantage compared to those that can be introduced with minimal impact to the existing fleet of vehicles. A fuel transition requiring changes in the existing fleet can significantly impact transition duration because fleet turnover typically takes 15 years or more [102]. For example, a transition to hydrogen in the LDV fleet, which requires new energy conversion devices such as fuel cells along with on-board reforming and/or storage system, would undoubtedly require substantial time due to the need for fleet turnover [103]. As mentioned previously, a transition to ethanol is not immune from this problem. In order to consume high blends of ethanol, FFV technology is necessary. Even if the technology does not incur significant costs relative to conventional vehicles, the fundamental barrier and time lag of fleet turnover still exists.

Viewing fuels and vehicles as a single technological system has been important to recent emissions reductions in the transportation sector. Prior to the implementation of the RFG program, vehicle manufacturers and oil companies jointly invested in a research program designed to quantify the emission impacts of changes in the formulation of gasoline. This joint research program, the Auto/Oil Air Quality Improvement Research Program (AQIRP), concluded that significant emission benefits were readily achievable (technologically and economically) through reformulated gasoline [45, 57]. The program "sought to identify those fuels and formulations that could be most effective in reducing ozone precursors without compromising drivability or substantially increasing the cost (per gasoline or diesel equivalent range) of driving [45]." By viewing the fuel as a critical component of a single technological system, the fuel introduces new variables in the design of the overall operation of the system, allowing for new approaches to the reduction of emissions. Perhaps more importantly, the AQIRP sought solutions that would have minimal impacts to performance and cost. If a proposed alternative fuel or fuel formulation reduces emissions, but results in poor vehicle performance and/or increased operating costs, it should be carefully scrutinized.

This principle was carried forward when the 2007 Highway Rule was crafted to reduce NOx and PM emissions from HD diesel engines. With limits on sulfur content in diesel fuel, PM emissions are directly reduced due to lower sulfate emissions, and the integration of aftertreatment devices into the overall engine system design—allowing for further reductions in PM and NOx—is enabled. Integrating the fuel into the overall system design allowed for a wider range of technological solutions to emissions challenges.

If the AQIRP principle is applied to the new challenges of climate change and energy security, rather than criteria air pollutants, then a new research program would "seek to identify those fuels and formulations that could be most effective in reducing *lifecycle GHG emissions and petroleum imports* without compromising drivability or substantially increasing the cost (per gasoline or diesel equivalent range) of driving." As an added benefit, when the fuel is viewed together with the vehicle, impacts to the distribution and retail infrastructure are likely to be minimized. This principle assumes that solutions to the challenges of climate change and energy security exist within the current transportation paradigm, i.e., liquid fuels powering IC engines. These new challenges might require the need to think outside of this paradigm. However, this principle can help to identify solutions that minimize impacts to the existing liquid fuels sector.

For example, biodiesel has been pursued as a solution in the DFO sector. Since biodiesel is not fully compatible with existing diesel-powered equipment, diesel engine and diesel fuel system manufacturers have placed limits on its use [104].[27] Synthetic distillate fuels (e.g., renewable diesel, FT diesel) could be used to overcome these limits. These fuels can be derived from many of the same feedstocks as biodiesel, while having the advantage of being chemically-identical to crude-based distillate. Therefore, they have the potential to reduce GHG emissions and petroleum consumption, like biodiesel, but have the advantage of not "compromising drivability" and being compatible with the existing DFO infrastructure. But, questions remain as to whether such fuels can be produced without "substantially increasing the cost of driving" when compared to conventional distillate [12, 105].

2.4.5 System boundaries

The analysis of historical events is influenced by temporal, spatial, and sectoral boundaries. The scope of the analysis, or boundaries, can influence the findings. When reconstructing historical events, a model is created. Like any model, historical models are limited through boundaries. When certain aspects of an historical event are neglected, critical or influential factors can be missed. For example, are economic factors examined, while cultural or societal factors are neglected?

In his review of leaded gasoline [97], Kovarik illuminates many of the controversies surrounding the development, use, and eventual elimination of lead

[27] For an expanded discussion on the compatibility of biodiesel with existing engines, and limits to its use, see sections 4.2.1.2 and 4.3.4.2.

additives in gasoline. Kovarik's account stands in sharp contrast to Seyferth's more science-oriented account of this history [30, 106]. Although not discussed in detail here, by expanding the boundaries of his historical analysis, Kovarik captured many factors that could have derailed the use of lead in gasoline well before its rapid growth in the 1930s. In the rush to adopt this technology, many warning signs were blatantly ignored, overlooked, and downplayed by corporations and governing agencies. A similar story is revealed by the Environmental Working Group's (EWG) account of the use of MTBE in gasoline [107]. By expanding the boundaries of their historical analysis to include the early development and use of MTBE by the oil industry, EWG researchers were able to reveal how the industry was well aware of MTBE's propensity to contaminate water supplies and the widespread problem of leaking underground storage tanks (UGSTs) well before the industry pushed to expand the additive's use through the RFG program.

The importance of analytical boundaries can be extended further. When a technology is developed or altered, understanding the potential impacts of the technology is critical. When the EPA proposes a new regulatory requirement, the agency must conduct a RIA. These assessments seek to quantify the impacts (e.g., economic, environmental, human health effects) of proposed regulations, which most often involve the introduction or modification of technologies. If the boundaries of an analysis are not chosen appropriately, important impacts of the technology may be neglected. For example, when the RFG program was implemented, the potential for water contamination was omitted. The analysis was limited to air emission impacts, and water pollution concerns were overlooked [108]. The importance of system boundaries is expanded in the next section on unintended consequences and the need to develop a lifecycle perspective.

2.4.6 Unintended consequences

Unintended consequences were found to be a common occurrence during historical fuel transitions, e.g., the use of MTBE in gasoline led to water contamination issues. When unintended consequences arise from the introduction of a new technology, another transition is likely to follow. Unintended consequences create the need to alter or substitute technologies and update regulations. When new technologies and/or regulations are being developed, and the impacts of these changes are assessed, approaching this analysis with a lifecycle perspective can help to limit the occurrence and severity of unintended consequences. With this approach, the potential for shifting problems, whether through energy, economic, societal, or environmental costs, is limited.

Lifecycle assessment (LCA) has become a critical component in the evaluation of alternative fuels. Biofuels must meet specific lifecycle GHG reduction thresholds in order to qualify for the RFS program. This regulation serves as the nation's initial attempt to enforce LCA standards on any type of product or service [14, 25]. By comparing alternative fuels to conventional fuels on a lifecycle basis, the regulation aims to prevent the adoption of new fuels that would produce increased GHG emissions over the lifecycle of the fuel. With previous fuel-use regulations, which focused on specific criteria air pollutants (e.g., NOx, CO), the question of lifecycle emissions did not come into play. These emissions cause local- and regional-pollution problems from the direct combustion of the fuel. In the case of GHG emissions, the impacts are global; the source of emissions is irrelevant and accounting of emissions must take place throughout the fuel supply chain.

Through increased production of ethanol, the nation aims to reduce petroleum imports and limit GHG emissions on a lifecycle basis. The feedstock production burden is shifted to agricultural commodities; fuel production is shifted to widespread biorefineries (i.e., distillers); distribution is shifted from pipelines to rail, barge, and trucking systems; and retailers must store and dispense this new fuel. These changes throughout the fuel supply chain have significant lifecycle implications, and not simply in terms of GHG emissions. If the assessment of this transition is limited to GHG emissions, many other negative outcomes—unintended or otherwise—have the potential to develop. For example, as production of monoculture crops such as corn is expanded, impacts to water consumption and contamination are expected [109]. Industrial-based monoculture cropping systems require massive inputs of synthetic fertilizers and pesticides, which contribute to nutrient pollution of surface and groundwater sources [109, 110]. The increased demand for biofuel feedstocks could exacerbate nutrient loading of the nation's water sources [111, 112]. The EPA is working to assess these potential impacts to water supplies, as evidenced in the RFS2 Draft Regulatory Impact Analysis (DRIA) [25]. But, since the RFS program does not place limits on such impacts, the full extent of these potential issues might not be realized before detrimental consequences occur. Increasing the production of some biofuels might pose a tradeoff between reduced GHG emissions and potentially increased contamination and consumption of water supplies.

At the opposite end of the fuel supply chain, another water issue is illuminated through lifecycle thinking. The combination of MTBE's use in gasoline and leaking UGSTs caused widespread cases of MTBE contamination in water supplies. As ethanol becomes more ubiquitous throughout the retail network, concerns about how this alcohol impacts groundwater supplies have been raised, e.g., the EPA has acknowledged these concerns in the RFS2 DRIA [25]. As explained in the DRIA, the problem is not necessarily that ethanol is a pollutant of concern, but that it readily biodegrades. Due to the biodegradation properties of ethanol, the BTEX (benzene, toluene, ethylbenzene, and xylene) plume accompanying an ethanol-blended gasoline leak can be extended. As the microbes preferentially consume ethanol, the BTEX plume propagates further, increasing the potential for BTEX exposure. Additionally, the potential for leaks may be increased with ethanol due to its corrosive properties and material compatibility requirements. Again, with the RFS2 regulation focused on GHG emissions, the rush to adopt ethanol without fully understanding these additional impacts could cause other water contamination problems.

The use of MTBE in gasoline did not significantly impact the distribution and retail industry. These segments of the supply chain were simply responsible for handling a new fuel, mainly in the form of RFG supplied to specific geographic regions. Due to the assumption that MTBE was compatible with the existing infrastructure, upgrades were not made (e.g., to address potentially leaky UGSTs). Although current information points to ethanol's potential to increase BTEX contamination of underground water supplies, the fuel is already becoming ubiquitous throughout the retail network. The nation has been operating under the assumption that low-level blends are compatible with existing retail infrastructure, while the potential for increased BTEX exposure stands unresolved.

An example of shifting economic burdens is illustrated by the use of MTBE as an oxygenate additive in RFG. The economic impacts were minimal in this case. But, the example serves to highlight the importance of how all costs, both monetary and otherwise, can be better understood through the use of lifecycle thinking. When blended with MTBE, RFG contains approximately 11.5% MTBE by volume. MTBE-blended RFG requires less petroleum to produce relative to conventional gasoline (CG) since a portion of the feedstock burden is shifted from petroleum to natural gas.[28] During the winter of 2000/2001, MTBE prices increased dramatically due to a rise in the price of natural gas. During the fourth quarter of 2000, the price of natural gas nearly doubled, raising the price of both normal butane and methanol. Consequently, RFG prices increased relative to CG. At the time of this occurrence, the EIA estimated that a $1 per MMBtu increase in the price of natural gas increased the cost of producing MTBE by $0.094 per gallon, raising the price premium of RFG over CG by $0.012 per gallon [113]. The overall cost burden is small in this case, but even a small shift from petroleum to natural gas led to a new dynamic in the price structure of gasoline. In a transition to biofuels, the pricing of liquid fuels will be influenced by a wide range of new factors that have never before played a role in the sector, e.g., droughts. With a heavy dependence on agricultural commodities, any fluctuation in commodity prices, e.g., due to reduced yields or increased farm input costs, could come to influence the cost of transportation fuels.

Following the rapid decline of MTBE in the gasoline supply, Davis and Thomas addressed the issue of unintended environmental consequences and proposed a methodology for evaluating fuel options, which explicitly integrates lifecycle thinking [114]. Like the researchers at EWG, Davis and Thomas look back in their analysis and

[28] As discussed in section 2.2.3, the primary feedstock in MTBE production is natural gas.

point to research conducted by the EPA Office of Research and Development in the late 1980s and early 1990s, prior to the implementation of the RFG program. The EPA was developing a research strategy to assess the benefits and risks of various fuels and formulations. Findings of the EPA work pointed to several concerns related to the use of ethers (e.g., MTBE and ETBE). These substances were found to be highly soluble in water and persistent in subsurface environments. In addition, the nature of emissions and releases of these substances from the storage and distribution infrastructure was not well understood. Davis and Thomas suggest that if "these warnings had been heeded, it seems likely that at least some of the problems that arose with MTBE could have been reduced or avoided." Based on the MTBE experience, they propose a systematic approach for evaluating the trade-offs among fuel options. The comprehensive environmental assessment (CEA) approach combines a product (e.g. fuel) lifecycle perspective with the more qualitative risk assessment paradigm, and attempts to examine environmental impacts of technologies in a broad, systematic manner. The approach does not explicitly encompass dimensions outside of the environmental realm, such as economic and societal factors, but it could be readily extended to capture these factors.

Erdal and Goldstein, also motivated by the MTBE experience, provide a more scathing critique of how the EPA handled the MTBE problem [108]. Again, by extending the boundaries of their analysis, they reviewed numerous studies conducted prior to the implementation of the RFG program. Based on this evidence, they suggest that widespread water contamination by MTBE was "predictable from the outset." The MTBE experience exemplifies the need to compile scientific information needed to make prudent policy decisions prior to exposing the public, and the environment, to a widely used technology.

2.5 Recommendations for further work

This review of historical fuel transitions could be expanded to include additional case studies. First, fuel transitions that have occurred in other nations could highlight experiences that have yet to occur in the U.S., including the widespread use of sugar-cane ethanol in the motor gasoline sector in Brazil (as a primary fuel); the production of coal-to-liquid fuels in South Africa; and the growth and subsequent contraction of the biodiesel industry in the EU. Second, several attempted transitions in the U.S. transportation sector could shed light on why some transitions fail, e.g., the Zero-Emissions-Vehicle (ZEV) mandate in California; the limited penetration of gaseous fuels in metropolitan areas and fleets; and the abandonment of methanol as a biomass-derived alcohol fuel. Lessons from failed transitions could illuminate barriers and missteps that might prevent a successful biofuels transition. Finally, transitions outside of the U.S. transportation sector could be examined, e.g., the residential heating sector serves as an example where several primary fuel sources serve the market simultaneously and transitions have been driven primarily through market forces.

2.6 Conclusions

This chapter has reviewed major fuel transitions that have occurred in the U.S. liquid fuels sector over the last half century. Transitions in the motor gasoline sector include the phasing out of lead additives in gasoline, the use of high octane hydrocarbons to recover octane in gasoline, the mandated use of oxygenate additives in gasoline, the transition from MTBE to ethanol as the predominant oxygenate additive in gasoline, and the ongoing growth of ethanol as a direct substitute for crude-based gasoline. The DFO sector has undergone two reductions in sulfur content in diesel fuel since the early 1990s: the introduction of LSD, and the transition to ULSD. These historical transitions represent the uncertainty and diversity of fuel transition pathways, and illustrate the range of impacts that can occur across the fuel supply chain infrastructure.

The liquid fuels sector is comprised of a massive, well-established network of industries and accompanying infrastructures, supported by and integrated with regulations, practices, and institutions. A transition to biofuels in the liquid fuels sector will not occur independently or in isolation from this system. Understanding how previous transitions progressed and altered this established sector is critical to understand any future transitions.

This review has shown that fuel transitions are a common occurrence in the liquid fuels sector. The time scales, or durations, of these transitions have been quite variable, ranging from approximately one year (e.g., introduction of LSD), to nearly 20 years (e.g., unleaded gasoline). The rate at which a fuel enters the market is influenced by how the properties and performance of the fuel change, since a significant change in the nature of the fuel can produce more far-reaching implications throughout the fuel supply chain. If a fuel transition requires additional fuels to be handled, rather than replacing an existing fuel, more challenges can arise, particularly in the distribution and retail segments, slowing the transition. The state of technology is another important factor influencing the duration of transitions. Fuels that require the development and application of immature technologies will be slow to enter the market.

Attempting to determine the rate at which a biofuels transition will occur is no simple task. It will be influenced by a number of factors, related to the properties of biofuels introduced into the market, the ability of these fuels to be handled with existing fuels throughout the infrastructure, and the state of technologies needed to produce and consume the fuels. Ethanol, the most common biofuel currently consumed in the liquid fuels sector, has properties that differ significantly from gasoline; it is handled separately throughout the distribution infrastructure; and its increased production will rely on the development of new technologies (e.g., cellulosic ethanol production technologies) and feedstocks, and the continued expansion of production capacity. As ethanol production expands to meet the RFS mandate, eventually exceeding the motor gasoline blend limit (10%), ethanol must be increasingly blended as E85.[29] When viewed in the context of the historical transitions, these factors point to a relatively slow transition, potentially exceeding the range of fuel transitions reviewed in this chapter, i.e., several decades.

Historical fuel transitions also highlight the utility of viewing vehicles and fuels as a single technological system. Fuels that can be used in the existing fleet of vehicles (and infrastructure) can be more easily integrated into the fuel supply, increasing the rate of market penetration, and decreasing economic costs. If a proposed alternative fuel, or

[29] The ethanol blend limit and growth of the E85 market are explored further in chapter 4.

fuel formulation, has the potential to negatively impact vehicle performance, or increase operating costs, it should be carefully scrutinized. With a well-developed, efficient, and expensive, petroleum-based infrastructure in place, introducing fuels that are incompatible could face more significant challenges than those fuels that differ little from existing conventional fuels. The example of biodiesel and bio-based synthetic distillate fuels served as an example of this principle being applied to the use of biofuels in the DFO sector.

System boundaries were shown to be an important factor in the analysis of historical fuel transitions. When assessing the potential impacts of a fuel transition, if the boundaries of the assessment, or analysis, are not chosen appropriately, important impacts can be neglected. Historically, such oversights have lead to the repeated occurrence of unintended consequences. When new fuel technologies and/or regulations (e.g. the RFS program) are being developed, and impacts are assessed, approaching this analysis with a lifecycle perspective can help to limit the occurrence and severity of unintended consequences: the potential for shifting problems, whether through energy, economic, societal, or environmental costs, can be limited. In a biofuels transition, if an environmental assessment is limited to GHG emissions, negative outcomes—unintended or otherwise—have the potential to develop. The potential for increased water consumption and contamination stemming from the production of conventional ethanol serve as an example.

Fuel transitions have the potential to impact not only technologies, but other components of the sociotechnical configuration in transportation. Getting the technologies right is not always enough; societal, regulatory, economic, and cultural factors can act as barriers as well. The misfueling problem during the lead transition in the motor gasoline sector serves as an example of a cultural barrier. Consumers fueled their catalytic-converter-equipped vehicles with leaded gasoline because they were unaccustomed with the new, unleaded fuel, and had misconceptions and concerns about its impacts on vehicle performance and reliability. Despite the fact that the technology was in place, and operational changes were implemented (e.g., different size fuel dispenser nozzles and filler caps), consumers' familiarity with leaded gasoline had to be overcome. A biofuels transition has the potential to impact many of these non-technology factors; identifying and addressing these potential barriers is just as important as overcoming challenges related to technologies. For example, as ethanol production has expanded, and ethanol has been increasingly incorporated into the gasoline supply nationwide, some consumers have started to push back, demanding gasoline that is free of ethanol [115].

Determining the economic impacts, or costs, associated with historical fuel transitions was found to be challenging. Fuel transitions do not occur in isolation from other events driving investments in the liquid fuels sector. For example, investments made by the refining industry during the 1980s were not solely related to the lead transition, but were driven by changes in product demand, crude oil supply, and other environmental regulations. Just as the technological and operational impacts of a fuel transition are spread across various segments of the fuel supply chain, costs are distributed amongst a range of stakeholders. Similarly, a biofuels transition will not occur in a vacuum. Other policies and trends in the liquid fuels sector will drive additional investments, unrelated to biofuels, e.g., fuel efficiency standards will force vehicle manufacturers to invest in new technologies and alter production strategies. Like historical fuel transitions, a biofuels transition will require investments from a range of stakeholders throughout the fuel supply chain.

The limitations of this analysis must also be acknowledged. As discussed previously, fuel transitions in a given sector caused incremental changes of the same technology and base fuels, i.e., there are no examples of interfuel substitution. Although this review highlighted two examples of petroleum feedstocks being partially displaced during fuel transitions (e.g., natural gas in the production of MTBE, corn in the production of ethanol), no major displacement of crude oil with alternative feedstocks has occurred. A biofuels transitions is unique in this regard, and these historical transitions provide little context for understanding the implications of a true interfuel substitution. When considering the simultaneously technological and operational changes that will be required throughout the fuel supply chain, a biofuels transition will be unprecedented in scope.

Chapter 3. Fuel Transition Models

"All models are wrong. Some models are useful." – W. Edwards Deming

3.1 Introduction

In order to better understand the barriers associated with switching fuels or technologies, and to identify options for overcoming these barriers, many recent research efforts have used sophisticated modeling techniques to analyze energy transitions. This chapter reviews a number of these recent modeling efforts with a focus on understanding how these methodologies have been applied, or may be adapted, to analyzing a transition to biofuels. The scope and approach to the modeling review is provided in the following section. A review of each "class" of models, with specific examples of recent and ongoing research efforts is provided in section 3.3. The paper will conclude with a general discussion of fuel transition models, including suggested applications and areas for further research.

3.2 Approach

The Renewable Fuel Standard (RFS) program caps the production of conventional biofuels at 15 billion gallons per year (bgy), and mandates the production of 16 bgy of cellulosic biofuel in 2022. Assuming that these categories of biofuel are produced as corn and cellulosic ethanol, respectively, 31 of 36 bgy of biofuel will be produced as ethanol. Since ethanol serves as an additive and substitute for motor gasoline, the light-duty vehicle (LDV) sector will be most impacted by the RFS mandate. Therefore, the scope of this review was primarily limited to models of ground-based, on-highway, gasoline-powered transportation

The main objectives, methods, and capabilities of each model are identified and critically examined. In order to identify and assess the capabilities of each model, a number of economic-, policy-, and technology-relevant questions are posed to determine how models capture spatial and temporal dynamics of the transition; incorporate drivers of technological change (e.g. R&D advancement, "learning by doing", economies of scale, uncertainty, and entrepreneurship and organization [116]); test the impact of government policies; track the economic costs and time scales associated with the development of new infrastructure; calculate energy and environmental metrics; include endogenous and exogenous variables; and simulate competition amongst fuels.

Spatial and temporal dynamics of a transition include the growth of the supply and distribution infrastructure, the penetration of new vehicle technologies in the market, and assessing the so-called "chicken-and-egg" syndrome. Many alternative fuels require the simultaneous development and market penetration of fueling infrastructure and new vehicles. The "chicken-and-egg" syndrome deals with the following question: which comes first, the fueling stations (and distribution channels) or the vehicles? Government policies can be tested by explicitly implementing policy components into a model or by simply altering assumptions and inputs to mimic a given policy structure. Identification of endogenous and exogenous variables proved to be a difficult task for most models due to limited or unclear documentation. Endogenous variables are altered, or determined, by other variables within the model, i.e., they are calculated within the context of the model. Exogenous variables are inputs to the model specified by the user, e.g., several models use demand forecasts from the EIA Annual Energy Outlook (AEO) as inputs, thereby specifying demand over time exogenously.

Although an emphasis was placed on a transition to biofuels, we discovered that many researchers have been examining challenges associated with a transition to the so-called "hydrogen economy." Although many of the models reviewed in this paper are focused on hydrogen, the methodologies are clearly pertinent to modeling a transition to biofuels as well. In reviewing each model, the primary focus was on understanding the methodologies employed rather than the models' results. Therefore, in the following section, little emphasis is placed on summarizing results and findings. In the section that follows, specific modeling efforts are summarized. The section is broken into four general categories of models: system dynamics, complex adaptive systems, infrastructure optimization, and economic models.

This review includes fuel transition models through November 2008. Developments (e.g., new models, further development of existing models, etc) that have occurred since this time have not been considered.

3.3 MODELS

3.3.1 System Dynamics

According to the System Dynamics Society, system dynamics is a methodology for managing and studying complex feedback systems; understanding and studying the feedback mechanisms present in a system is at the root of this field. The field developed from the work of Jay W. Forrester following the publication of his book Industrial Dynamics in 1961. System dynamics has been applied to problems in a range of disciplines including corporate planning and policy, biological and medical modeling, and energy and the environment [117]. When considering the expansive, complex nature of the transportation sector, it seems plausible that the system dynamics methodology could be applied to analyzing the fuel transition problem. The first model reviewed uses a system dynamics methodology to analyze the cellulosic ethanol industry.

The Biomass Scenario Model (BSM) is being developed at the National Renewable Energy Laboratory (NREL) in collaboration with the Peterson Group, and is funded by the DOE Office of the Biomass Program [118]. This prototype model was spawned from a larger biomass initiative launched in 2003, called the Role of Biomass in America's Energy Future (RBAEF) project.[30] The BSM has been developed to investigate market penetration scenarios of the nascent cellulosic ethanol industry. Understanding the growth of this industry is viewed as a "classic" system dynamics problem, involving change over time, the interaction of multiple stakeholders with diverse interests, interdependencies between sub-systems and processes, and difficulty in communicating issues and structure of the system. The model is being developed in the STELLA (Systems Thinking Experimental Learning Laboratory with Animation)

[30] The current state of the RBAEF project is unknown due to the limited information provided on the project's website: http://engineering.dartmouth.edu/rbaef/index.shtml.

software platform; STELLA is a popular system dynamics modeling program developed by ISEE Systems.[31]

The central operation of the model is driven through investment decisions. The model tracks the development of the industry as technologies improve over time and the investment community reacts to demand for biofuels, government policies, and competition from the oil market. The model represents the physical infrastructure required at each stage of the supply chain, including feedstock production and logistics, biofuels production (i.e. conversion facilities), delivery and distribution, and end use. The main components and interactions of the model are illustrated in Figure 3-1.

[31] See http://www.iseesystems.com/softwares/Education/StellaSoftware.aspx for details.

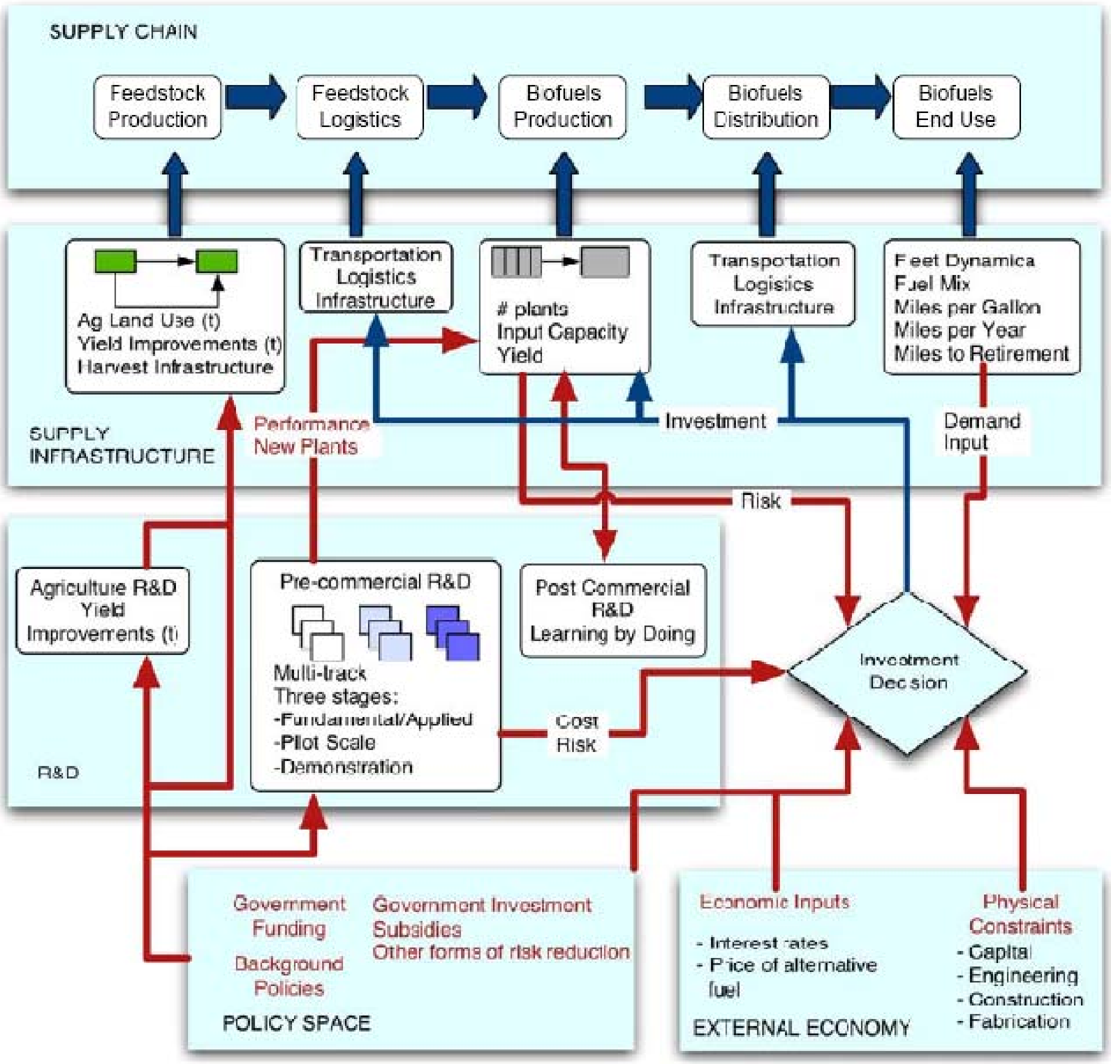


Figure 3-1. A schematic of the BSM; individual model components provide inputs to and are driven by investment decisions [118].

Although the supply chain is well represented in this model, the current prototype does not account for fuel transportation and distribution. The authors of the model assumed that this component of the supply chain would not be rate-limiting to industry growth. They acknowledged the potential shortcomings of this assumption and plan to integrate a module representing this link in the supply chain in the next release of the model. The BSM incorporates many R&D efforts associated with technologies spanning the supply chain, including yield growth in cellulosic crops, improved conversion technologies, and post-commercial "learning by doing" cost reductions. Understanding how these factors are represented and incorporated is unclear due to the current documentation. As the industry develops during a simulation, the model accounts for overall industry investments and spending by the government to support various policies, but does not track environmental costs and benefits. The later factors are being investigated for incorporation in subsequent releases of the model [118].

The prototype model was initially used to investigate the impacts of two policy scenarios through 2017. These include subsidies to reduce operating costs (e.g. feedstock grower payments, production subsidies analogous to the present day Volumetric Ethanol Excise Tax Credit) and/or to reduce capital costs (e.g. subsidies for commercial-scale plants). The model calculates various performance metrics, such as ethanol production volume, feedstock inputs, number of operating facilities, cumulative government spending, impact of spending on production, and impact of spending on capital investment by the industry. The researchers stressed the importance of interpreting current results with "healthy skepticism" due to the early stage of model development, but seem encouraged by initial results and the potential this project has for informing policy and decision making aimed at developing the nascent cellulosic ethanol industry [118]. The BSM is not available in the public domain at this time, and it is unknown if the model will be released to the public following subsequent revisions.

A similar system dynamics model, developed at the School of Natural Resources and the Environment at the University of Michigan (UM) and funded by BP p.l.c., explores the market challenges facing the implementation of advanced ethanol technologies over the next 40 years in the U.S. corn belt [119]. The model was not explicitly named, and will henceforth be referred to as the BP-UM model. The same software platform used to develop the BSM, STELLA, was used to develop the BP-UM model. The framework of this model is built on the interactions and decisions of farmers and bioprocessors (i.e. conversion facility owners) as major decision-makers in the biofuels industry.

The BP-UM model has been used to simulate industry growth up to an ethanol volume that yields E10 (10% ethanol) blends and below. Therefore, complications associated with the development or modification of distribution infrastructure and the sale and use of flex-fuel vehicles (FFVs) were not addressed. Although the vehicle/fueling-station aspect of the "chicken-and-egg" syndrome was not addressed, a similar issue was investigated: which comes first, the farmers producing cellulosic feedstock or investors building cellulosic ethanol refineries? This important dynamic is obviously a challenge when considering the substantial costs associated with these critical decisions facing farmers and investors. The model incorporates a GHG emissions calculation to compare emissions relative to a business-as-usual case when all demand is met with petroleum fuels. Policy analysis was not conduced, but the modular format of the model should allow for a policy component to be implemented. When the report was published, policies could only be tested through "proxy" parameters, such as an increase in farmers' willingness-to-pay, which could, for instance, reflect biomass feedstock tax incentives.

Acknowledging the parallels with the BSM, the UM researchers put forth a recommendation to establish a future collaboration with NREL. In addition, an effort is apparently underway through the UM SMART (Sustainable Mobility and Accessibility Research and Transportation) Program[32] to build on the BP-UM model to produce an interactive system dynamics model of multiple alternative fuels. Publications and further information on such efforts could not be located.

The final system dynamics model included in this review, a collaborative effort between NREL and MIT System Dynamics Group, focuses on the transition to a hydrogen-fueled transportation system. The Hydrogen Dynamic Infrastructure and Vehicle Evolution (HyDIVE) Model, a spatial, behavioral, and dynamic market simulation model, was initially developed by MIT researchers to explore the dynamics

[32] See http://um-smart.org/ for details.

associated with the transition to an alternative-fuel-vehicle (AFV) system in general. In collaboration with NREL, the project was focused on exploring the development of hydrogen as a transportation fuel in support of the DOE Hydrogen Program [120-122]. The core of the HyDIVE model has been developed with VenSim software.[33]

A major difference between the HyDIVE model and the aforementioned models is the integration of spatial dynamics to investigate how demand and infrastructure may grow temporally and spatially within a given simulation region. In contrast, this model only investigates the end of the supply chain and does not include upstream activities in feedstock supply, hydrogen production, and delivery; only hydrogen distribution and end use are simulated. The main objective of this project is to develop an understanding of the barriers associated with the "chicken-and-egg" problem that hydrogen faces. Vehicle demand and refueling infrastructure (i.e. hydrogen refueling stations) growth are endogenous variables; the model allows users to truly explore how demand growth may come about and be sustained over time in a given spatially-resolved test region. The HyDIVE model is still under development with many components yet to be incorporated, such as cost accounting and endogenous effects related to economies of scale and learning by doing in manufacturing and technology improvements.

In reviewing these system dynamics models, it became evident that this methodology should not be confused with general optimization methodologies. By incorporating the decision-making processes of individuals in the system, optimal solutions are not necessarily obtained. This non-optimal behavior of decision-making stakeholders is perhaps more indicative of the complexities that play out as new technologies are developed in society.

3.3.2 Complex Adaptive Systems

According to Luis Rocha [123], a complex system is "any system featuring a large number of interacting components (agents, processes, etc) whose aggregate activity is nonlinear (not derivable from the summations of the activity of individual components)

[33] See http://www.vensim.com/software.html for details.

and typically exhibits hierarchical self-organization under selective pressures…and applies to systems from a wide array of scientific disciplines." Complex adaptive systems (CAS), as the name implies, are complex systems with elements that have the capacity to adapt, evolve, and learn from interactions and experiences within the system over time. One approach to exploring CAS is through Agent-Based Modeling and Simulation (ABMS). ABMS is a micro-simulation technique that is readily applied to economic and behavioral models involving actors, or agents, with varying characteristics and objectives, making decisions based on limited information. The technique is well suited to representing diversity in complex systems, and, like the system dynamics methodology, does not enforce an optimal solution. The simulated agents can learn and adapt through interactions with other agents and changes in the system environment, and make decisions and respond according to individually assigned "personalities" [124]. The model that follows uses an ABMS methodology to explore aspects of the hydrogen transition similar to those of the HyDIVE project.

The Hydrogen Complex Adaptive System (H2CAS) model is being developed by the Decision and Information Sciences Group at Argonne National Laboratory (ANL) in collaboration with RCF Economic and Financial Consulting Inc., and is funded by the U.S. DOE [124, 125]. The modeling platform is an open source agent-based modeling toolkit called Repast Simphony.[34] The main purpose of this model is to track the market penetration of hydrogen-powered vehicles and hydrogen fueling stations both spatially and temporally in a given study region. The current model simulates the transition over a 20-year time period in metropolitan Los Angeles. Figure 3-2 illustrates the road topology and population density of the test region incorporated in the H2CAS model.

[34] See http://repast.sourceforge.net/ for details.

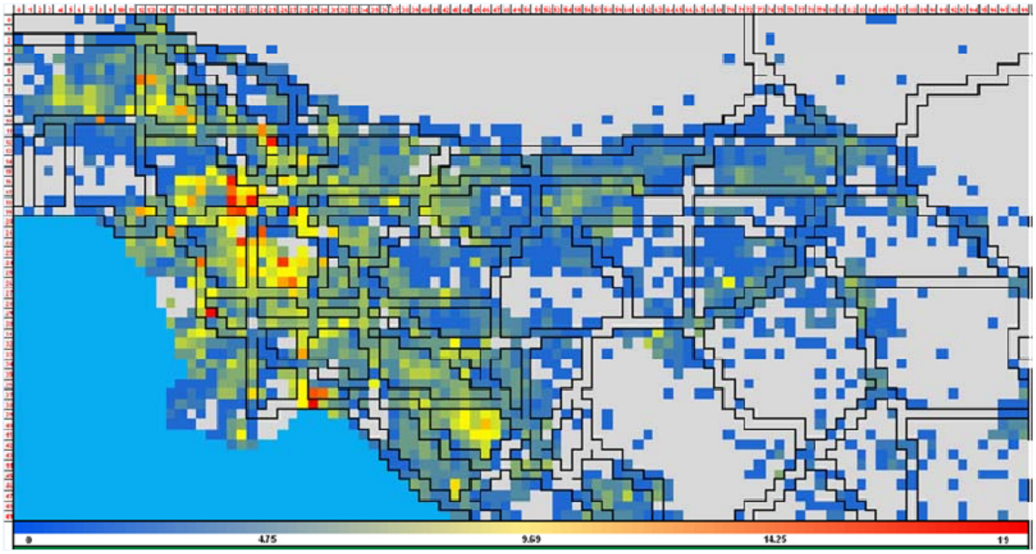


Figure 3-2. The road topology and population density (households per square mile) of metropolitan LA as incorporated in the H2CAS model [124].

The model incorporates driver agents and investor agents attempting to maximize their own utility functions. Driver agents buy either hydrogen-powered or conventional vehicles, drive to various locations, and purchase fuel; varying personality types are assigned to driver agents to reflect a diversity of purchasing behaviors. Investor agents build fueling stations in strategic locations to make a profit from fuel sales. Like HyDIVE, no aspects of the upstream supply chain are included, thus restricting the scope of analysis to the end use market. In the full model, which is under development, investor agents will be required to decide whether their hydrogen supply will come from distributed production or from centralized plants with pipeline or truck deliveries. Given that this project is still in early stages of development, the authors of the model emphasize that the preliminary results are not indicative of conclusions from the overall project [124]. It is believed that this methodology will reveal how the inherent complexity associated with the "chicken-and-egg" conundrum will evolve under varying circumstances. For instance, subsidies or other government interventions can be incorporated into simulations to understand how market penetration will respond.

Schwoon published results on a similar effort applied to the German trunk road system [126]. An ABSM approach was adapted to study the adoption of hydrogen-powered vehicles based on initial small-scale distributions of hydrogen fueling stations. The main conclusion drawn from this study seems to imply that such modeling approaches may inevitably rely on the ability to quantify consumer behavior: "We find that the structure of an optimized initial distribution of filling stations depends on what drivers consider a sufficiently small distance between refueling opportunities." No other examples of CAS models applied for fuel transitions were identified during the course of this review.

3.3.3 Infrastructure Optimization

Whereas the system dynamics and CAS approaches do not seek optimal solutions in terms of economic, environmental, or other cost/benefit parameters, this section focuses on methodologies developed to explore the optimal development of alternative fuel infrastructures. We have termed these models as "infrastructure optimization" models.

Researchers at the Sustainable Transportation Energy Pathways (STEPS) Program at the UC Davis Institute of Transportation Studies (ITS)[35] have developed sophisticated regional spatial and temporal optimization methodologies for analyzing the development of alternative fuel infrastructures. These models have been applied primarily to hydrogen production and distribution pathways, but could be adapted to study other alternative fuels. One research effort, which—in initial applications—was referred to as the Hydrogen Infrastructure Transition (HIT) model, has been used to identify optimal pathway strategies for supplying hydrogen to the metropolitan Beijing and Southern California regions [127, 128]. These two regional applications use different data, pathways, geographic scope and resolution, but the underlying methodology and model structure is the same [129]. The methodology is based on dynamic programming resource allocation models. The model determines the spatial and temporal infrastructure

[35] See http://steps.its.ucdavis.edu/ for details.

development decisions over time that minimize net present value of capital and operating costs, carbon emissions, and refueling disbenefits. Regionally-specific data, such as road networks, traffic flows, and demand distributions, are incorporated to determine the infrastructure development based on an exogenously desired market penetration; future revisions of the model may treat demand as an endogenous variable. Input assumptions, such as technological advances, feedstock prices, carbon policies, and market penetration rate, can be varied to assess how the optimal approach may be altered.

In another recent study conducted at UC Davis, a methodology was developed to optimize supply chains for producing and delivering hydrogen from dispersed biomass resources [130]. This profit-maximizing model, constructed in a mixed-integer nonlinear program,[36] determines the optimal number, location, and size of biomass-to-hydrogen conversion facilities, the optimal mode of hydrogen delivery for producing and delivering hydrogen, and even identifies the fields that supply each facility and which demand regions are served by which facilities. As a case study, the methodology was applied to hydrogen production from rice straw in Northern California.

The Hydrogen Deployment System Modeling Environment (HyDS ME) is a GIS-based infrastructure optimization model being developed at NREL [131, 132]. It is built around the HyDS model, which estimates the cost of various hydrogen pathways to determine the most economic delivery of hydrogen to a given region. Cash flow models, GIS tools, and an optimization routine are combined to design the least-cost infrastructure for a user defined region, forecast year, and desired hydrogen vehicle penetration, amongst other variables. Unlike the HIT model, HyDS ME provides only a "snapshot" of the optimal infrastructure at the user defined forecast year. The development of infrastructure over time is not determined. Due to limited documentation, it is unclear how this model will be further developed. Based on work conducted by Lambert, it seems that HyDS ME could be upgraded to include temporal dynamics as well. Lambert's model, the Hydrogen Network Optimization and

[36] Mixed integer-non-linear programs are non-linear programs that incorporated both integer- and continuous-type variables.

Orchestration for the Nation (HyNOON), utilizes an optimization methodology called "simulated annealing" to minimize total life cycle costs of developing hydrogen fueling infrastructure over time in a given region [133].

3.3.4 Economic Models

The following models apply economic modeling techniques to understanding fuel transitions on a national level, rather than from a local or regional perspective. Samples include the National Economic Modeling System (NEMS) and the Hydrogen Transition (HyTrans) model.

The HyTrans model, developed at Oak Ridge National Laboratory (ORNL) and funded by the U.S. DOE Hydrogen Program, is an integrated market equilibrium simulation model used to produce scenarios of a transition from conventional vehicles to hydrogen-powered vehicles in the light-duty vehicle (LDV) market through 2050 [134, 135]. HyTrans is a dynamic, multi-period, non-linear optimization model that seeks to optimize social surplus (i.e. welfare) of rational economic agents, including hydrogen producers, distributors, and retailers, vehicle manufacturers, and consumers. Unlike the models that follow (NEMS, MARKAL), HyTrans does not attempt to model the entire U.S. energy economy.

Documentation of the HyTrans model does not explicitly state what platform was used to build the model, but it is assumed that the core elements of the model are based in the General Algebraic Modeling System (GAMS).[37] This assumption is based on the fact that HyTrans evolved from the Transitional Alternative Fuel Vehicle (TAFV) model, which was also developed in GAMS. A review of hydrogen transition models conducted by the Argonne National Laboratory (ANL) confirms this assumption [136]. The TAFV model simulates the use and cost of various alternative fuels and vehicles to assess the barriers in a transition to alternatives [137, 138]. The underlying methodology is similar to HyTrans, but this earlier model incorporated the competition of several alternatives fuels, including LPG, CNG, ethanol, methanol, and electricity; and vehicle technologies,

[37] See http://www.gams.com/ for details.

including conventional, dedicated, flex-fuel, and hybrid vehicles. Based on analysis conducted with the TAFV model, researchers at ORNL concluded that transitional barriers would prevent any significant penetration of alternatives in the LDV market; the primary barrier to success was cited as price competitiveness.

The high-level structure of HyTrans is illustrated in Figure 3-3. The dark, cylindrical components represent independent models that provide exogenous inputs (e.g. AEO forecasts, Hydrogen Analysis (H2A) production models) and process output data (e.g. ANL Greenhouse gases, Regulated Emissions, and Energy Use in Transportation (GREET) model) for HyTrans scenario analyses. The model allows for a range of hydrogen production pathways to be evaluated and implemented; pathways are comprised of a production process, delivery mode, and refueling type. For example, a production method could be hydrogen from biomass with or without CO2 capture; delivery modes include pipelines, liquid trucks, and compressed gas trucks; refueling options include liquid and compressed gas. These modes are selected in various combinations to form least cost pathways in the development of a hydrogen infrastructure. The model incorporates spatial resolution, to some degree, by defining geographic regions and subregions of fuel demand density. Vehicle sales and stocks and hydrogen demand (production and consumption) are tracked in each region and subregion.

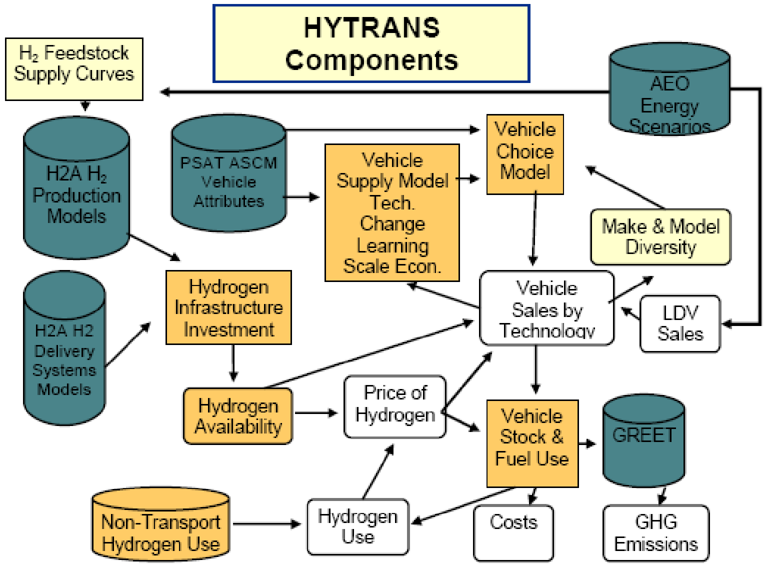


Figure 3-3. HyTrans integrates components of the hydrogen vehicle and fuel market to conduct transition scenario analysis [135].

A lack of diversity in vehicle choices has been identified as an important market barrier to alternatives. To account for this issue, HyTrans incorporates a consumer vehicle choice component, which is based on a nested multinomial logit (NMNL) mathematical framework [139]. Technological improvements, economies of scale, and learning factors are all represented to account for potential cost reductions in hydrogen technologies and infrastructure. Without the consideration of these cost reducing effects, the success of a hydrogen transition is diminished.

Initial analysis consisted of three early market transition scenarios implemented as constraints through 2025. After this early market transition, the constraints are removed and the competitive outcome is determined. This approach allows for the R&D and learning effects to play out and assess whether the early market scenario constraints establish sufficient conditions for the hydrogen transition to be sustained economically. Costs associated with the early market scenarios represent costs that must be subsidized, undoubtedly by the government, to successfully manage the early market transition. In summary, the model allows the user to "force" an early market transitional scenario and test whether such an approach, or policy, would sustain a full market penetration of hydrogen-powered vehicles in the long term.

GHG emissions are computed with the GREET Model.[38] Emissions are compared to a business-as-usual case to reflect the change in emissions resulting from the transition to hydrogen. Interestingly, HyTrans results indicate that policies aimed at reducing carbon emissions do not aid in the transition to hydrogen. But, such policies are crucial to ensure that hydrogen is produced via low carbon or carbon-free sources. Without such policies in place, hydrogen is produced primarily from cheap fossil resources without sequestration technologies [135].

The National Energy Modeling System (NEMS) is a general equilibrium energy-economy model of the U.S. energy markets. The model was designed and implemented by the U.S. DOE Energy Information Administration (EIA) and is used to create the Annual Energy Outlook [140]. NEMS is composed of several individual modules representing supply, conversion, and end use portions of the energy markets. The individual modules communicate through an integrating module, as illustrated in Figure 3-4. The integrating module drives the solution algorithm, calling the individual modules in sequence until market equilibrium is achieved each year.

The market penetration of alternative fuels and vehicles is primarily determined within the Transportation Demand Module of NEMS [141]. Technological innovation, macroeconomic feedback, infrastructure constraints, and vehicle choice are endogenously incorporated into this module. The market shares of alternative fuels are calculated by a vehicle attribute model; based on the literature, it appears as though this vehicle attribute model is derived from the same NMNL framework as the vehicle choice model incorporated in HyTrans [139]. NEMS attempts to model competition between a wide array of alternatives in the market, including: gasoline, TDI diesel, flex-fuel methanol and ethanol, dedicated ethanol, dedicated CNG and LPG, CNG and LPG bi-fuel,

[38] See http://www.transportation.anl.gov/modeling_simulation/GREET/index.html for details.

dedicated electric, diesel/electric hybrid, gasoline/electric hybrid, plug-in gasoline/electric hybrid, and methanol, hydrogen, and gasoline fuel cell vehicles.

A major function of NEMS is to investigate the impacts of policies on the U.S. energy markets. For instance, the full release of the AEO 2008 report was significantly delayed in order to incorporate the impacts of EISA 2007, which revised and implemented a variety of energy laws and policies. Interestingly, the AEO 2008 projects a shortfall in meeting the 36 bgy of biofuels mandated by the RFS in 2022; slow technological progress in the cellulosic ethanol industry combined with caps on conventional corn ethanol is cited as the reason for this shortfall [142].

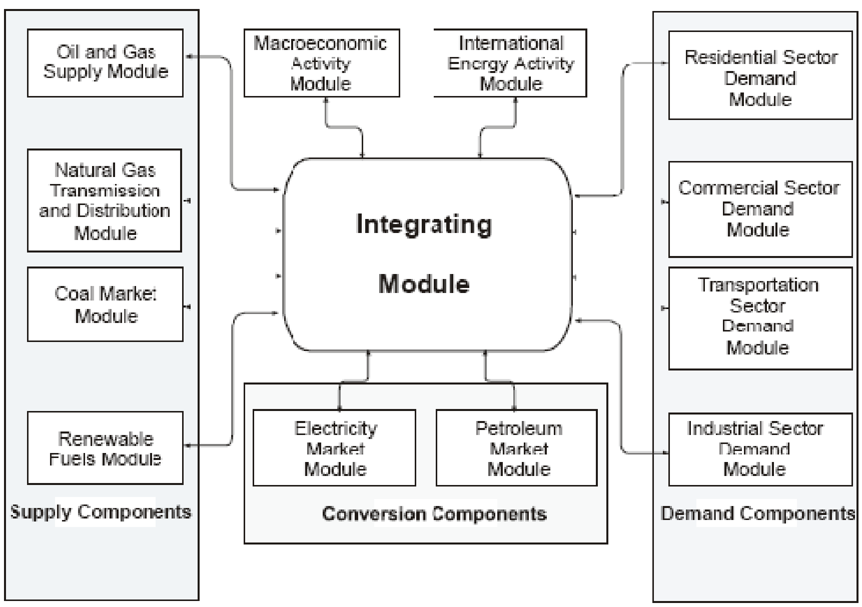


Figure 3-4. NEMS is composed of individual modules that communicate through an integrating module [140].

The MARKet ALlocation (MARKAL) model, first developed at Brookhaven National Laboratory in the 1970s, is the U.S. EPA's model of the U.S. energy system. MARKAL is a data-driven, energy system optimization model that includes, amongst a slew of various outputs, a determination of the technological mix at various periods in the future [143]. Further review of the literature is needed to determine whether this model includes alternative fuel technologies. Although this model was not reviewed in detail, it is worth citing here.

One additional economic model is the USDA Policy Analysis System (POLYSYS). Although this model does not analyze the transition to alternative transportation fuels, it does serve as an important source of data on feedstock supply of biomass-derived fuels. For instance, cellulosic feedstock supply curves, derived with POLYSYS, are used as inputs to the BSM. POLYSYS was developed by the Agricultural Policy Analysis Center at the University of Tennessee and is used by the USDA's Economic Research Service to conduct economic assessments of the U.S. agriculture markets. This modular economic simulation modeling system was modified in 2002 to create realistic energy crop supply curves, including cellulosics, such as switchgrass, hybrid poplar, and willow [144, 145].

3.3.5 Model Summary

A summary of the fuel transition models covered in this review is provided in Table 3-1. The table succinctly illustrates the breadth of approaches, objectives, and capabilities of various fuel transition models. Note that a few of the models mentioned in the previous sections are not included due to limited information in the literature, or minimal differentiation from other models included in the table. Although additional energy or fuel transition models exist in the literature, these models provide a good sampling of the approaches that researchers have employed in studying this problem. In the following section, a discussion on fuel transition modeling, along with some suggested applications and areas for improvement and further research, are provided.

3.4 Discussion

This review has served to illustrate the breadth and depth of various modeling efforts aimed at resolving the many barriers facing a transition to alternative transportation fuels. Given that these models span a number of disciplines (e.g.

economics, system dynamics, complex systems, operations research, information science, etc), and to aid in facilitating an open dialogue amongst those working in the field of energy transition modeling, detailed model documentation should be made readily accessible. Access to high-quality documentation can improve the ability to interpret results, understand methodologies, and build on synergies.

A 2007 report by ANL researcher, S. Plotkin, provides several recommendations for improving the field of fuel transition modeling [136]. Although the report is focused on hydrogen transition models, such as HyTrans, most of the recommendations are applicable to any sort of energy transition modeling effort.

When conducting a modeling exercise, it is important to establish a well defined set of research questions. The type of modeling approach used to analyze fuel transitions is best dictated by the questions being addressed. For a biofuels transition, these questions might include [136]:

- What are the costs and benefits of a biofuels transition, including GHG emissions, oil consumption, investment costs, etc?
- Will biofuels development occur if the world unfolds as envisioned (e.g., if oil prices, economic development, policies, etc. follow a business as usual pathway)? Or, under what circumstances will biofuels development unfold?
- Given a desired outcome (e.g., x billion gallons of biofuels used in LDVs in a given year, or more generally, satisfying transportation energy demand over a specified period at the least social cost), what is the most desirable path to arrive at this outcome?
- What is an appropriate allocation of resources for an R&D program for a biofuels transition? What technologies most demand improvement?

This list is far from being all inclusive of the range of questions that could be addressed with transition modeling. At the same time, no single transition model or approach is capable of answering each of these questions. Plotkin explains this point further: "It is quite possible that the most practical approach to modeling a…transition will be the development of a few models that will each be focused on specific types or ranges of questions and audiences." Based on his review of hydrogen transition models, Plotkin proposes a list of characteristics for the ideal transition model [136]:

- clear documentation;
- ability to specify/construct output tables and figures;
- parametric analysis capability;
- Monte Carlo simulations using probability distributions for key variables;
- reasonable level of spatial disaggregation;
- robust vehicle choice model;
- ability to track variables that help measure scenario realism;
- incorporate algorithms that add to scenario realism (e.g., by automatically adjusting parameters, or alerting user to unrealistic parameter values);
- wide analytic boundaries, e.g., cross-sector interactions;
- ability to model a variety of government policies;
- modular structure;
- appropriate investment model, including investment rules and disaggregation of types of investors.

Although the resources attributed to any single modeling effort may preclude the ability to incorporate all characteristics from this "wish list," these items can serve as a guide to the further development of existing models and the creation of new models used to explore transition pathways to alternative transportation fuels and technologies.

Based on the objectives of certain modeling efforts, or research questions being posed, some of these characteristics may not be applicable whatsoever. For instance, the infrastructure optimization models, aimed at determining the optimal development, both spatially and temporally, of alternative fuel infrastructure, may not be concerned with individual, or even aggregate, vehicle purchasing behavior. Since the demand function is an exogenous variable, at least in the current implementation of these models, the vehicle population, or fuel demanded by end users, is predetermined. Therefore, the incorporation of a vehicle choice model would be unnecessary. On the other hand, the scenario realism characteristics could be applied to the infrastructure optimization models to ensure that the computed results can hold water. For instance, although the model may compute an optimal development pathway based on the user-specified demand function, is the rate of infrastructure development (e.g., construction of new fuel retail sites, new distribution networks, etc) feasible? Are there sufficient resources (e.g., manpower, capital) available to undertake such an infrastructure development project? The model would not necessarily need to alter parameters during a given simulation, but could provide alerts to the user when certain parameters exceed a set of defined "realism" boundaries.

The issue of realities, or realism, is an important one when discussing simulation models. In a rather scathing, yet substantive, review of energy modeling and forecasting efforts, Vaclav Smil attributes the record of failed modeling endeavors to the complex nature of energy markets and the issue of realities [146]. The modeling of transitions, or forecasting of energy markets, presents unique challenges not present in the modeling of other complex systems, which are devoid of social, economic, technical, and environmental factors. Smil explains the issue as follows [146]:

> There is no shortage of…outstanding examples of complex realistic modeling ranging from photosynthetic productivity of crops to the flight aerodynamics of jumbo airplanes. All of these disparate modeling successes share a common denominator: they deal with systems that, although extraordinarily complex, lack complex interactions of social, economic, technical, and environmental factors that govern the course of energy production and use (p. 168).
>
> But there is nothing new about modelers' predilections for built-in complexity. They think they can do better by making their creations progressively more complex, by including more drivers and more feedbacks. They do not seem to realize that a greater complexity that is required to make such interactive models more realistic also necessitates the introduction of more questionable estimates

> (which can soon turn into pure guesses) and often also of longer chains of concatenated assumptions—and these necessities defeat the very quest for greater realism. As the variables become more numerous and time horizons more distant, quantifications becomes inevitably more arbitrary. And, even more importantly, no matter how complex a model might be and how lucky a forecaster can get in nailing a particular rate or share (or even a chain of assumptions) it is simply impossible to anticipate either the kind or the intensity of unpredictable events (p. 172)

Sperling addressed this issue nearly two decades earlier. Like Smil, Sperling attributes these challenges to the complexity inherent to technological systems [92]:

> As new technologies proliferate and societal systems become more complex, the challenge of understanding the process of change and anticipating the future becomes increasingly important. But even as computers become more powerful and less expensive, discernment of the future remains elusive. While in the past, planning and forecasting relied principally on knowledge and intuition, the emphasis has now shifted toward the development and application of sophisticated mathematical modeling techniques…
>
> The combination of increased power and decreased cost of computing has tempted analysts and researchers to build more sophisticated models and to incorporate more variables and data into those models and analytical constructs. As a result, analytical capabilities have improved dramatically, even while our understanding of underlying phenomena and of relations between the many variables has not always kept pace. In many applications, models have been rich while data remain poverty stricken. A mismatch has developed between modeling sophistication and the knowledge used to build and calibrate those models. Obviously, this failing is not everywhere true. Where it is most true, however, is with large and complex systems.
>
> Since the complex and multiobjective behavior of humans is highly unpredictable, one might suppose that as the presence of humans in these large, complex systems shrinks, quantitative evaluations and representations would be simpler, more accurate, and therefore more useful—and planners, forecasters, and policy analysts could proceed with greater confidence in their tasks.
>
> But in a technology-based system, bringing the full weight of mathematical modeling to bear is not necessarily fruitful, even though human behavior is not at the heart of the analysis. Technologies do not develop or evolve in response to some set of universal laws. Technologies and technology-based systems evolve in response to goals, values, and beliefs of dominant social groups. Since this is

> the case, immutable laws of nature do not guide the evolution and development of transportation energy systems, and their future design and performance cannot necessarily be predicted by the use of more sophisticated and detailed quantitative treatments. (p. 23-24).

Based on these views, and considering the complex nature of energy markets (e.g., the transportation sector), the usefulness of energy transition models could be discounted. However, before jumping to such a conclusion, the true objectives of these modeling efforts will be reviewed. For most of the modeling efforts covered in this review, the modeling objective is not necessarily to predict, or forecast, per se. This assumption may not be applicable to all efforts. For example, the primary use of NEMS is to produce energy forecasts for the Short-Term Energy Outlook (STEO) and AEO reports published by the EIA. These forecasts are relied upon heavily by government (e.g., for policy making), industry (e.g., for budget planning and strategy development), and academic institutions. Unfortunately, the record of these forecasts, particularly the long-term forecasts, is questionable [147]. On the other hand, many of the transition models are aimed at answering much more focused questions associated with fuel transitions, and are not necessarily designed for forecasting. For example, the HyDIVE and H2CAS models are being developed to investigate the hypothetical market penetration of hydrogen refueling and vehicle infrastructure in spatially- and temporally-resolved, real world geographic regions. The objective is not to predict how this market penetration will unfold, but to uncover the barriers to market penetration in the end use segments of the fuel supply chain. The infrastructure optimization models, using exogenous demand inputs, clearly are not seeking to forecast market penetration of new fuels. Rather, if a transition to a given transportation technology (e.g., hydrogen) is desired or mandated (based on the demand function), these models seek to explore the optimal spatial and temporal development of fuel production and distribution infrastructure. These optimized solutions, again, are not viewed as predictions of how the infrastructure development would unfold, but instead serve as potential designs, and should be used to explore potential pathways based on various optimization criteria and varied input parameters.

By viewing transition models as tools for exploring potential pathways to alternative fuel futures, the pitfall of prediction and forecasting can be avoided. As explained by Sperling, technology-based systems "evolve in response to goals, values, and beliefs" held by society at large. If society decides that, for example, a transition to biofuels in the liquid fuels sector is an advantageous path forward, then these transition modeling tools can be used to explore such a pathway, i.e., these modeling tools can serve as a compass, not a map.

In a discussion on general factors characterizing technological diffusion, Gruebler explains that diversity and complexity at the microlevel result in overall orderly transition paths [116]. The system dynamics and complex adaptive systems (CAS) approaches seem focused on capturing this diversity and complexity at the individual level and perhaps will show that this characteristic of technological diffusion can be generally modeled. Even if the quantitative results of system dynamics and CAS models prove to be inaccurate, the greatest value of these efforts may lie in the rigor and methods employed in the modeling process, which force the modeler to uncover and develop new knowledge of complex system interactions, feedback loops, and other evasive parameters. This system thinking perspective is crucial in developing sound policies and guiding prudent investments in the nascent alternative fuel industries.

One potential research opportunity to explore is the calibration of a system dynamics model to an historical case study. For instance, the model could be used to "back-cast" the historical growth of the existing corn-based ethanol industry by using real data on current and historical growth. This calibration exercise would help to refine the understanding of investor behavior, identify key factors and interactions that have driven growth of the industry to present day, and explore the impacts that changing policies have had on the industry. This work was proposed at an OBP review of the BSM in 2005 [148], but the latest documentation on this project provides no indication that this work has been carried out [118]. Such a "back-casting" effort could be analogous to long-range climate modeling efforts that have been shown to reproduce records of long-term historical climate fluctuations [149].

The infrastructure optimization models have the potential for assessing regional transition issues associated with feedstock supply and infrastructure development. For example, the majority of citrus waste in the U.S. is produced by the Florida citrus industry; nearly 68% of U.S. citrus production was attributed to Florida in 2005/2006 [150]. This waste stream has the potential to become a meaningful feedstock supply for ethanol production in Florida. Using infrastructure optimization methodologies, the supply chain to collect, convert, and deliver this waste stream as a useful fuel product to high demand regions of Florida could be optimized. Such a modeling effort could be used to determine the number and location of ethanol refineries required to process the waste stream, and to identify potential markets for the new source of ethanol and how the fuel is most optimally distributed and integrated into the infrastructure. A similar approach could be applied to other regionalized feedstocks and perhaps extended to exploring pathways for optimal algae biofuel infrastructure development.

In order for these methodologies to produce high-quality, spatially-resolved results, they must be based on high-quality, spatially-resolved input data. Such data are most readily supplied with advanced GIS tools. Researchers at UC Davis and NREL have been developing and utilizing a range of GIS tools to produce data on feedstock resources, fuel demand distributions, existing energy infrastructures, and other relevant spatially-resolved data [151-155]. As GIS capabilities expand, the infrastructure optimization methodologies, along with spatially-resolved CAS and system dynamics models, will have the ability to become more robust in assessing barriers to fuel transitions.

The economic models included in this survey are most applicable to analyzing transitions from a nationwide or regional perspective. Implications associated with federal and state policies aimed at promoting a particular alternative can be readily assessed. But, the development and direct application of such large-scale models is no simple task. For example, NEMS is not widely used outside of the DOE due to the complexity and relatively high cost of proprietary software needed to execute the model [156]. Although the capabilities of these energy-economy models are expansive, the most straightforward use of these models may be to provide reference data as inputs for other models and analyses aimed at resolving specific questions related to fuel transition pathways.

A major challenge in the transition to alternatives is the competition among alternative fuels and technologies for market share, energy resources (i.e. feedstocks), and capital [157]. Unfortunately, modeling the transition of a single fuel has proven to be a challenge, let alone capturing the dynamics of competing technologies. There are few models in this survey that attempt to account for a range of alternatives. NEMS does incorporate 16 various vehicle technologies, but the model does not capture the many complexities, beyond economic factors, that play out amongst competing alternatives. The only effort identified that could be used to address this challenge is the effort that may (or may not) be underway through the UM SMART Program. As mentioned earlier, this effort was to build on the BP-UM model to produce an interactive system dynamics model of multiple alternative fuels; publications and further information on this effort were not found.

Opening the scope of this review to include transitions in the electricity sector could prove to be beneficial. Transition modeling efforts applied to the electricity sector might be used to explore a transition to renewable and cleaner technologies, such as wind (and new transmission infrastructure) and carbon capture and sequestration technologies. If such modeling efforts have been conducted, the methodologies and underlying approaches could be compared to those reviewed here. Finally, synergies between electricity and fuel transition models could be identified, e.g., the penetration of electric vehicles (EVs) and plug-in hybrid electric vehicles (PHEVs) in the LDV fleet will involve both sectors, requiring an understanding of cross-sectoral impacts.

3.5 Conclusions

Many challenges surround the transition to alternative transportation fuels and technologies. This chapter has served to illustrate the breadth and depth of various modeling efforts aimed at identifying and resolving these challenges. Four general categories of models were reviewed: system dynamics, complex adaptive systems, infrastructure optimization, and economic models. Although many of the models reviewed in this chapter were developed for hydrogen, the methodologies are clearly pertinent to modeling a transition to biofuels as well. These models can be used to investigate a range of economic-, policy-, and technology-relevant issues facing a transition to biofuels. Models incorporate a range of features, such as the ability to test the potential impacts of government policies; track the economic costs and time scales associated with the development of new infrastructure; and calculate energy and environmental metrics.

The complex nature of the liquid fuels sector, which incorporates technological, social, economic, and environmental factors, presents the modeler with unique challenges. Attempts at forecasting, or predicting transitions, are ultimately doomed to fail. However, the objective of transition modeling does not have to be scoped in this manner. The value of modeling efforts lies not in their ability to forecast, or predict specific transition events, but in their ability to reveal interdependencies, uncover potential barriers, and identify critical variables. By viewing transition models as tools for exploring potential pathways to alternative fuel futures, the pitfall of prediction and forecasting can be avoided. The greatest value of these modeling efforts may lie in the rigor and methods employed in the modeling process, which can help to uncover and develop new knowledge of complex system interactions, feedback loops, and other evasive parameters.

Some suggested applications and areas for further research were highlighted. For example, infrastructure optimization models could be developed to explore the development of fuel production and distribution infrastructure around regionalized biofuel feedstock supplies and end use markets. With different assumptions related to feedstock supply (e.g., availability, and geographic and seasonal distribution), growth in fuel demand, etc, alternative spatial and temporal designs of the infrastructure could be assessed.

Based on this review, it is evident that no single model can provide all the answers facing a biofuels transition; and for that matter, no combination of models can provide all the answers. It is recommended that an appropriate modeling methodology can only be selected after a well-defined research question (or set of questions) has been formulated. For instance, the infrastructure optimization models may not be particularly useful when attempting to understand the barriers to simultaneous penetration of FFVs and E85 fueling infrastructure. The identification of barriers to a biofuels transition, and strategies or means for overcoming and mitigated these challenges can be explored through the use of fuel transition models. However, much work remains to be done to improve the capabilities of this rapidly advancing field.

Table 3-1. The following table illustrates the breadth of approaches and capabilities of fuel transition models.

Model Type	Model Name	Platform	Organization(s)/ Sponsor(s)	Fuel/vehicle technologies	Description	Strengths / Weaknesses (i.e., capabilities)
System Dynamics	Biomass Scenario Model (BSM)	STELLA	National Renewable Energy Laboratory (NREL), Peterson Group; DOE Office of the Biomass Program	Cellulosic ethanol	Investigates market penetration scenarios of the cellulosic ethanol industry; model tracks industry development as technologies improve and investors react to biofuel demand, policies, and oil prices; physical infrastructure of the fuel supply chain is represented.	(+) incorporates drivers of tech. change (+) test impacts of government policies (+) track economic costs (-) environmental metrics excluded from current prototype (-) fuel distribution not represented in current prototype (-) no competing alternatives (-) not accessible in public domain
	BP-UM (model name given by the author)	STELLA	University of Michigan (School of Natural Resources and the Environment; BP	Cellulosic (and conventional) ethanol, low-level blends	Explores market challenges facing the implementation of advanced ethanol technologies in the Corn Belt; models interactions and decisions of farmers and biorefinery owners.	(+) investigates farmers' decisions to produce dedicated energy crops (+) tracks GHG emissions relative to BAU baseline (+) test impacts of government policies (through proxy variables) (-) avoids infrastructure complications of mid- to high-level blends (-) no competing alternatives (researchers proposed for further work) (-) model use controlled by BP, i.e., not accessible in public domain
	Hydrogen Dynamic Infrastructure and Vehicle Evolution Model (HyDIVE)	VenSim	NREL, MIT System Dynamics Group; DOE Hydrogen Program	Hydrogen	Spatial, behavioral, and dynamic market simulation of the development of hydrogen as a transport fuel; model aims to understand barriers to simultaneous penetration of vehicle and fueling infrastructure.	(+) spatially- and temporally-resolved demand and infrastructure (+) investigates dynamics of the "chicken-and-egg" problem (+) model will incorporate cost accounting and drivers of tech. change (-) models only distribution and end-use segments of the supply chain (-) no competing alternatives (-) under development, i.e., not accessible in public domain
Complex Adaptive Systems (CAS)	Hydrogen Complex Adaptive System (H2CAS)	Repast Simphony	Argonne National Laboratory (ANL), RCF Economic and Financial Consulting; DOE	Hydrogen	Spatially and temporally tracks the market penetration of hydrogen-powered vehicles and hydrogen fueling stations within a given study region using ABMS technique.	(+) spatially- and temporally-resolved demand and infrastructure (+) investigates dynamics of "chicken-and-egg" problem (+) test impacts of government policies (-) models only end use segments of the supply chain (-) no competing alternatives (-) under development, i.e., not accessible in public domain

Table 3-1 (continued).

Model Type	Model Name	Platform	Organization(s) / Sponsor(s)	Fuel and vehicle technologies	Description	Strengths / Weaknesses (i.e., capabilities)
Infrastructure Optimization	Hydrogen Infrastructure Transition (HIT)	unknown	UC Davis ITS, STEPS Program (Lin et al.)	Hydrogen	Dynamic programming resource allocation model that optimizes regional fuel infrastructures (spatially and temporally) to minimize NPV of capital and operating costs, carbon emissions, and refueling disbenefits.	(+) model incorporates real-world, regionally-specific data (+) vary tech. advances, feedstock prices, carbon policies as inputs (+) evaluates various production and distribution pathways (-) market penetration determined exogenously (user-specified) (-) no competing alternatives (again, user-specified demand) (-) not accessible in public domain (under further development)
	not specified	unknown	UC Davis (Parker et al.)	Biomass-to-hydrogen	Mixed-integer nonlinear program determines optimal biomass-to-hydrogen production and distribution infrastructure from field to market using a profit-maximizing function.	(+) model incorporates real-world, regionally-specific data (+) evaluates various distribution pathways (+) determines optimal feedstock supply locations for demand regions (-) market penetration determined exogenously (-) no competing alternatives (-) not available in public domain (status of model unknown)
	Hydrogen Deployment System Modeling Environment (HyDS ME)	unknown	NREL; DOE	Hydrogen	Incorporates cash flow models, GIS tools, and an optimization routine to design least-cost (spatially-resolved) infrastructure for a user-specified region, year, and market penetration.	(+) GIS tools incorporate real-world, spatially-resolved data (+) evaluates various production and distribution pathways (-) market penetration determined exogenously (-) model solution computed for user-specified forecast year only (-) no competing alternatives (-) not available in public domain (status of model unknown)
Economic (CGE/GEM)	Hydrogen Transition (HyTrans)	GAMS	Oak Ridge National Laboratory (ORNL); DOE Hydrogen Program	Hydrogen	Integrated market equilibrium simulation model that produces scenarios of a transition to hydrogen-powered vehicles; dynamic, multi-period, non-linear optimization model seeks to optimize welfare of rational economic agents.	(+) evaluates various production and distribution pathways (+) tracks GHG emissions relative to BAU baseline (+) incorporates drivers of tech. change (+) attempts to quantify subsidies needed to sustain market transition (~) competition limited to hydrogen, conventional, and hybrid vehicles (-) model optimizes welfare according to “rational” economic decisions (-) relies on AEO forecast for inputs (exogenous demand inputs) (-) not available in public domain
	National Energy Modeling System (NEMS)	Fortran	DOE Energy Information Administration (EIA)	Various conventional and alternative	General equilibrium energy-economy model of U.S. energy markets; commonly known as the model that produces AEO forecasts; market penetration of alt. fuels and vehicles determined within a submodule of NEMS	(+) incorporates drivers of tech. change (+) attempts to model competition amongst wide array of alternatives (+) test impacts of policies on energy markets (e.g. RFS2 program) (~) model is available to public; requires high-cost, proprietary software (-) complex CGE attempts to model entire U.S. energy market (-) model optimizes welfare according to “rational” economic decisions

Chapter 4. Scenarios and Barriers to a Biofuels Transition

"Just imagine...running America's inefficient cars on corn-derived ethanol, most likely at a net energy loss!" - Vaclav Smil, Energy at the Crossroads

4.1 INTRODUCTION

Biofuels are being adopted in greater volumes in the U.S. liquid fuels sector. Looking to the future, the continued adoption of biofuels will be influenced by many factors. Policies adopted at the federal and state levels, and by corporations and institutions, will play a major role in a transition to biofuels. The Renewable Fuels Standard (RFS) program has played a crucial role in the recent growth of the biofuels sector.[39] Table 4-1 summarizes the volume mandates of the RFS program as established by the Energy Independence and Security Act (EISA) of 2007. This program stands as a key driver in a transition to biofuels in the near term. By mandating annual consumption of biofuels, increasing to 36 billion gallons per year (bgy) in 2022, the program has the potential to significantly alter the state of the U.S. liquid fuels sector.

[39] The RFS program is discussed in greater detail in chapter 1.

Table 4-1. The RFS2 mandates annual consumption of biofuels through 2022 [14, 25].

Year	Cellulosic Biofuel	Biomass-Based Diesel	Total Advanced Biofuel	Total Renewable Fuel
2009	0.00	0.50	0.60	11.10
2010	0.10	0.65	0.95	12.95
2011	0.25	0.80	1.35	13.95
2012	0.50	1.00	2.00	15.20
2013	1.00		2.75	16.55
2014	1.75		3.75	18.15
2015	3.00		5.50	20.50
2016	4.25		7.25	22.25
2017	5.50		9.00	24.00
2018	7.00		11.00	26.00
2019	8.50		13.00	28.00
2020	10.50		15.00	30.00
2021	13.50		18.00	33.00
2022	16.00		21.00	36.00

With the context of the RFS program as the key driver in a transition to biofuels in the liquid fuels sector, this chapter examines several scenarios that help to illustrate the range of futures and uncertainty that exists in assessing such a transition. These scenarios also serve to identify barriers that could hinder the market penetration of biofuels. The analysis will focus on fuel-specific issues, avoiding issues related to feedstocks. By focusing on fuel-specific barriers, this chapter does not address issues related to the selection and production of biofuel feedstocks. This includes the growth, harvesting, collection, storage, and logistics associated with feedstock supply. Therefore, in this analysis, it is assumed that feedstock limitations are not a concern; barriers associated with biofuel production, distribution, retail, and end use are the central focus. Although the analysis is limited to barriers downstream of feedstock production, the importance of feedstocks should not be downplayed. Without a sustainable and sufficient supply of feedstocks, the barriers that arise throughout the remainder of the biofuels supply chain become irrelevant. However, to ensure a manageable scope, this portion of the supply chain has been excluded from the analysis.

As the RFS program mandates greater volumes of biofuels, there is substantial uncertainty facing the liquid fuels sector as to how such a transition will unfold. Ethanol derived from grain corn overwhelmingly dominates the biofuels sector today. Moving forward, the mix of biofuels being produced and consumed could change substantially. Different fuels have different implications as they penetrate the market. Therefore, understanding the barriers associated with the introduction of different fuels and fuel blends is critical. As illustrated by the review of historical fuel transitions, each new fuel requires different changes along each segment of the fuel supply chain. This analysis will identify barriers that face a biofuels transition, including challenges that are unique to different types of biofuels. Since ethanol is currently the biofuel of choice in the U.S., and is poised to maintain this dominant role moving forward, substantial attention will be given to barriers facing the continued transition to ethanol in the motor gasoline sector.

A set of simple projections, or scenarios, of the liquid fuels sector was developed using a model of the sector—the Liquid Fuels Transition (LiFTrans) model. Each scenario is based on the RFS mandate and is thus limited to the timeframe of the mandate, extending no further than 2022. They illustrate different pathways to meeting the requirements of the RFS mandate, producing no more or less than the mandated volumes. These scenarios differ based on the overall demand of liquid fuels, how the biofuels mandate is met (i.e., fuel mix), and other important factors such as ethanol blend limit. The scenarios serve as a starting point for evaluating the associated infrastructure implications for different fuels and penetration rates.

Prior to introducing the LiFTrans model, projections made by the Energy Information Administration (EIA) are reviewed. The Annual Energy Outlook (AEO) 2009 projections of the motor gasoline and DFO sectors are presented. The updated 2009 reference case is presented first, followed by a brief review of alternative cases, which are based on differing assumptions related to economic growth and world oil prices. These projections serve as an input to the LiFTrans model, which is presented in section 4.3.

The inputs, assumptions, structure, and implementation of the model are discussed in detail. Using the model, a series of transition scenarios are presented in section 4.4. These scenarios are then analyzed in section 4.5.

4.2 AEO PROJECTIONS

Each year, the EIA produces the AEO, a report detailing the agency's outlook on energy markets in the U.S. extending several decades into the future (e.g. AEO 2009 assesses energy markets through 2030). The National Energy Modeling System (NEMS), discussed in some detail in chapter 3, is the general equilibrium model used by EIA analysts to produce the quantitative projections presented in the AEO reports each year. The AEO includes projections of all sectors of the U.S. energy market, including the liquid fuels and transportation sectors. Table 11 of the AEO report, Liquid Fuels Supply and Disposition, serves as the input data for the charts presented below. The Liquid Fuels Supply and Disposition table includes data on annual volumes of liquid fuels consumed through 2030 in million barrels per day (MMBD). Several sets of data from this AEO data table are used as inputs to the LiFTrans model, presented in the section 4.3. Since this data set serves as a critical component of the model, it is useful to first present the data and to examine the EIA's projected future of the liquid fuels sector.

4.2.1 AEO stimulus case

The reference case projection from the most recent AEO report, released in April 2009, will be presented first. This reference case, referred to here as the "stimulus" case, was published following the initial release of AEO 2009 in order to reflect the provisions of the American Recovery and Reinvestment Act (ARRA) implemented in mid-February 2009 [158]. The initial publication of AEO 2009 in March 2009 was based on laws and regulation in place as of November 2008. Therefore, the stimulus case includes several important energy-related provisions that could affect energy markets and the overall macroeconomic outlook for the U.S. Some energy-specific provisions of the ARRA that were implemented in the modeling of the stimulus case that could impact the liquid fuels sector include the plug-in hybrid vehicle tax credit, electric vehicle tax credit, and loan guarantees for biofuels projects. In addition, the stimulus case includes updates to the Corporate Average Fuel Economy (CAFE) standards proposed by the National Highway Traffic Safety Administration (NHTSA) for light-duty vehicles (LDVs) through 2015. The EIA assumed that the standards would increase to 35 mpg on average in 2020, and remain constant thereafter.

Using the stimulus case, projections of the motor gasoline and DFO sectors through 2030 are presented and discussed below.

4.2.1.1 Motor Gasoline

The motor gasoline projection includes consumption of total motor gasoline, crude-based gasoline, total ethanol, and ethanol-gasoline blends through 2030. Data are taken from the Liquid Fuels Supply and Disposition table of the stimulus case, or Updated AEO2009 Reference Case Service Report [159]. Figure 4-1 presents the motor gasoline projection from 2005 through 2030. Figure 4-2 presents the same data with historical data from chapter 2. This figure places the projected trends in the context of previous transitions and illustrates the growth in overall demand since 1970.

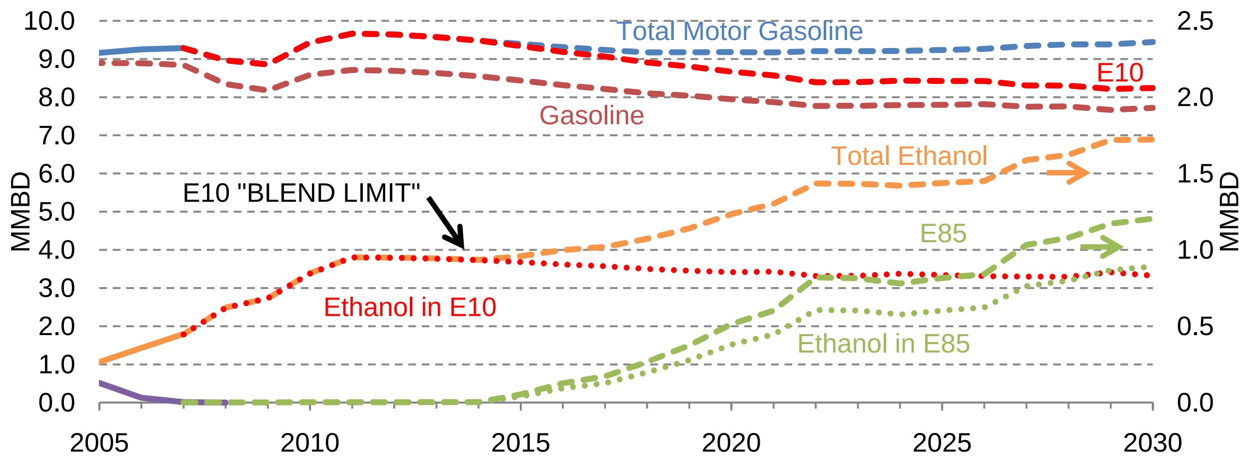


Figure 4-1. The AEO 2009 stimulus case projection of the motor gasoline sector through 2030 shows a transition to increased consumption of ethanol and E85, and decreased consumption of crude-based gasoline (i.e., Gasoline). The EIA projects total gasoline demand to plateau after 2010. The upper data sets (Total Motor Gasoline, E10, and Gasoline) are read from the left axis of the chart; the remaining data sets are read from the right. Gasoline represents all crude-based gasoline consumption, in both low-level blends (e.g., E10) and E85.

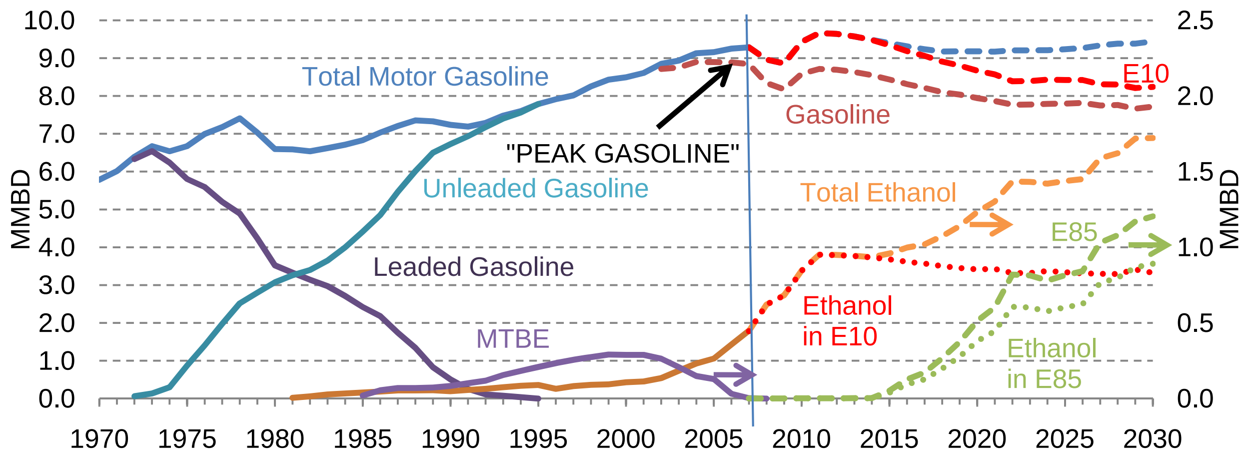


Figure 4-2. The AEO2009 stimulus case projection of the motor gasoline sector through 2030 is combined with historical trends starting in 1970. The leaded and unleaded gasoline data sets are read from the left axis of the chart; the MTBE data set is read from the right.

In this projection, the only alternative to crude-based gasoline is ethanol. Ethanol consumption continues to grow rapidly through 2011, remains constant until 2015, and resumes growth until 2022. The EIA assumes that after 2022, the RFS mandate will remain constant at 36 bgy. Total ethanol and crude-based gasoline (i.e. Gasoline) sum to the total motor gasoline supply. The projection shows that this total supply, or consumer demand, plateaus through 2030. With no growth in overall demand, and increasing ethanol demand, the demand for crude-based gasoline must fall. This reduction in crude-based gasoline demand creates what has been termed "peak gasoline," the point at which consumption of gasoline peaks and declines thereafter. According to the EIA, this peak occurred in 2007, when gasoline consumption reached 8.84 MMBD, or 135.5 bgy. Along with EIA analysts, many private consultants and oil industry executives have acknowledged the "peak gasoline" phenomenon. The EIA does not expect gasoline consumption to return to 2007 levels in the future [93].

As total ethanol consumption increases, gasoline consumption does not decrease on a one-to-one, or barrel-to-barrel, basis. Since ethanol has a lower energy content compared to gasoline (76,330 and 115,261 Btu/gallon, respectively),[40] a greater volume of ethanol is required to replace a barrel of gasoline. For each volume unit of gasoline, 1.5 volume units of ethanol are required to replace the gasoline on an energy basis.

Figures 4-1 and 4-2 show trends in E10 and E85 consumption, along with the breakdown of ethanol consumed as E10 and E85. Summing the ethanol consumed as E10 and E85 gives the total ethanol consumption. Summing the E10 and E85 consumption gives the total motor gasoline consumption. The data series related to E10 (E10 and Ethanol in E10) represent the average blend level of ethanol and gasoline, not including E85. They represent volumes of blends less than or equal to 10%. These low-level blends can range from 0% to 10% ethanol in gasoline, and are sold as standard motor gasoline for all gasoline-powered vehicles and equipment. Currently, the Clean Air Act (CAA) limits the sale of gasoline to blends of ethanol no greater than 10%. The blend limit was established by a waiver to the "substantially similar" rule under section

[40] See Table 4-4.

211(f) of the CAA [160]. This limit has been referred to as the "blend limit" or "blend wall." Once this limit is reached in the gasoline supply, all further increases in ethanol consumption must come in the form of E85 or other high level blends (>10%).[41]

E85 consumption is negligible until approximately 2014, at which point it begins a rapid growth trend that continues through 2022. In the same year, the 10% blend wall is reached (see Figure 4-1). The projection shows that the average blend of ethanol in the gasoline pool slowly increases to 10%, with E85 making up a negligible component of this supply. After the blend wall is reached, further increases in ethanol consumption come in the form of E85. Additionally, as the volume of crude-based gasoline available for blending declines with increased total ethanol demand, ethanol consumed as E10 must inevitably decline. After the blend wall is reached, if the gasoline supply was blended to E10, there would not be enough gasoline available to incorporate the remaining ethanol into the market as E85. Therefore, E10 consumption must decline. This is not simply a result of the blend wall, but is also based on the flat demand for total motor gasoline products in this projection. If total demand were to increase at a rate comparable to total ethanol demand (on an energy basis), then the market could continue to be supplied with E10, forgoing the need for ethanol to be consumed as E85.

In this projection, total motor gasoline demand on an energy basis is approximately equivalent in the years 2018 and 2030. As total ethanol consumption increases by 0.65 MMBD from 2018 to 2030, the ethanol consumed as E85 increases by 0.69 MMBD, while the ethanol consumed as E10 decreases by 0.04 MMBD. Even as the total energy demand remains flat during this time period, the total volume increases by 0.27 MMBD, from 9.18 to 9.44 MMBD, due to the lower energy content of ethanol. As ethanol comprises a greater percentage of the overall motor gasoline pool, a greater overall of volume of fuel must be supplied relative to a business-as-usual case (e.g., ethanol consumption remains flat as total demand increases). By 2029, ethanol is consumed in greater volumes as E85 compared to E10. This transition is shown in

[41] The "substantially similar" rule and ethanol blend limit are discussed in greater detail in section 4.4.2.

Figures 4-1 and 4-2 when ethanol consumed as E85 increases above the ethanol consumed as E10.

The rate of market penetration of different fuels (e.g., E85) is also an important factor. For a given projection in total motor gasoline and ethanol demand, a required market penetration of E85 can be determined based on the 10% blend wall and an assumption that E85 consumption remains negligible until the blend wall has been reached. The rate at which E85 must penetrate the market determines the pace at which market transitions must occur (e.g., fleet of flex-fuel vehicles (FFVs) in the market, retailers capable of dispensing E85, etc). In this projection, E85 increases from approximately 0.5% of total motor gasoline volume in 2015 to 12.8% in 2030. This penetration rate requires the market to increase its capability to supply E85 from 0.05 MMBD (2.2 million gallons per day) to 1.20 MMBD (50.6 million gallons per day) in a span of 15 years.

4.2.1.2 Distillate Fuel Oil (DFO)

The DFO projection includes consumption of total distillate, crude-based distillate, non-crude-based distillate, bio-based distillate, and biodiesel through 2030. Bio-based distillate includes biodiesel and liquids-from-biomass; non-crude-based distillate includes bio-based distillate and coal-to-liquid distillate. Like the motor gasoline projection, data are taken from the Liquid Fuels Supply and Disposition table of the stimulus case, or Updated AEO2009 Reference Case Service Report [159]. Figure 4-3 presents the DFO projection from 2005 through 2030. Figure 4-4 presents the same data with historical data from chapter 2. This figure places the projected trends in the context of historical transitions and illustrates the growth in overall distillate demand since 1990. Since the AEO projection does not differentiate between sulfur grades of distillate fuels, only historical trends of the grades of distillates are plotted.

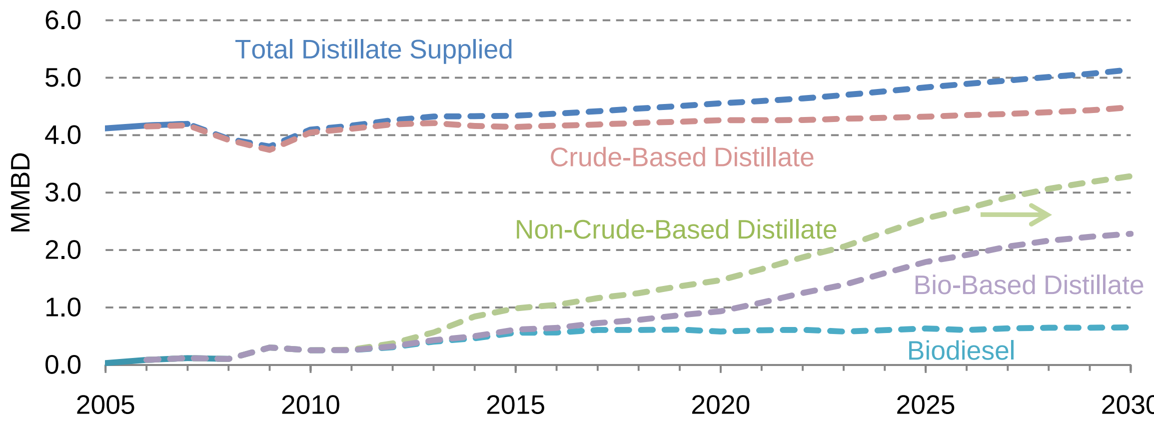


Figure 4-3. The AEO 2009 stimulus case projection of the DFO sector through 2030 shows increasing consumption of bio-based and other non-crude-based distillate fuels. Despite these increases, consumption of crude-based distillate continues to increase due to the rapid growth in overall distillate demand. The upper data sets (Total Distillate Supplied and Crude-Based Distillate) are read from the left axis of the chart; the remaining data sets are read from the right.

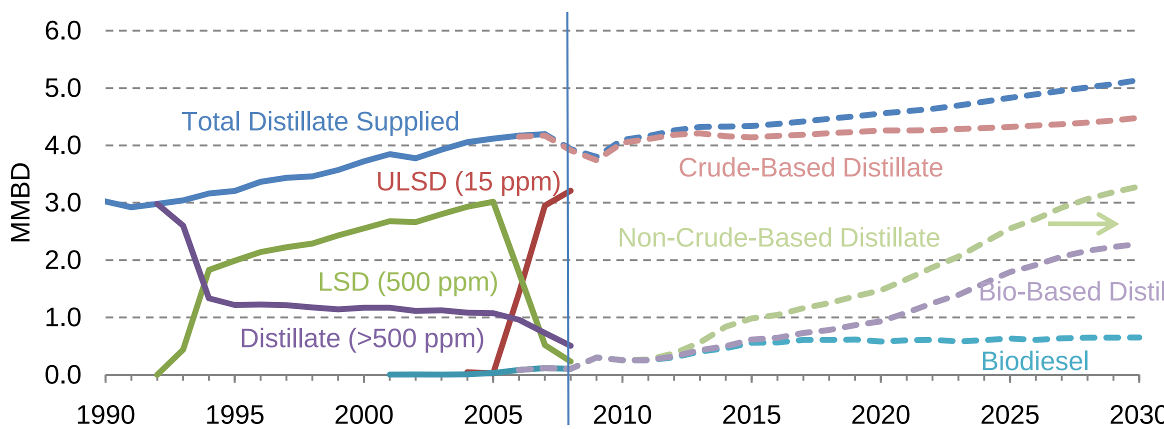


Figure 4-4. The AEO2009 stimulus case projection of the DFO sector through 2030 is combined with historical trends starting in 1990. The historical data sets are read from the left axis of the chart.

As mentioned above, bio-based distillates may come in the form of biodiesel (e.g., fatty-acid-methyl ester) or liquids-from-biomass. Liquids-from-biomass represent any biomass-derived distillate that is chemically identical to crude-based distillate, e.g. renewable diesel and biomass-to-liquid (BTL) fuels (e.g., FT diesel).[42]

With the modest penetration of biofuels and growth in total distillate demand starting in 2010, there is no evidence of a peak in crude-based distillate consumption through 2030. Therefore, the "peak gasoline" phenomenon observed in the motor gasoline sector is not anticipated in this projection. A transition in oil refinery operations would be required to supply the increasing market demand for distillates and reduced demand for gasoline.

In addition, no issues related to a "blend limit" or "blend wall" are anticipated. Diesel-engine manufacturers place limits on biodiesel use, but the projected volumes of biodiesel fall well below any concerns about reaching a blend wall during the timeframe of this projection. Biodiesel's share of the DFO pool grows to just under 3% in 2015, and holds this share through 2030. Currently, diesel engines are warranted to run on blends of biodiesel up to 5%, i.e., B5. This acceptance of B5 blends is reflected in the latest version of the ASTM distillate fuel oil specifications, D975 and 396, which allow for distillates to be blended with up to 5% biodiesel. The specifications ensure that a biodiesel-blended fuel meets all requirements of D975 or 396, and that the neat biodiesel, i.e., B100, used in the blend meets the ASTM biodiesel specification, D6751 [161]. Even if biodiesel demand grows beyond the 5% blend level, several diesel-engine manufacturers have warranted engines that are approved to operate on B20, and even B100 in a few instances [104], ensuring a larger market for biodiesel. The other bio-based distillates, e.g., renewable diesel and BTL, face no blend limitations. Ignoring the fact that these fuels are projected to comprise a minimal percentage of the DFO sector,

---

[42] Renewable diesel (RD) is a diesel substitute derived from oil-based feedstocks through hydro-treating processes. BTL is a diesel substitute derived from various cellulosic feestocks through gasification and FT processes; it is also known as cellulosic diesel or FT diesel. Both fuels are high-quality synthetic distillate substitutes with similar heating values.

these fuels are chemically identical to crude-based distillates, ensuring their unrestricted use in the current DFO infrastructure.

The EIA projection shows that biofuels in the DFO sector will play a smaller role compared to ethanol's role in the motor gasoline sector. The final year of the RFS mandate—2022—serves as a useful point of comparison between the two sectors. On a volume basis, ethanol is projected to comprise 15.6% of the motor gasoline pool in 2022, while bio-based distillates are projected to comprise only 5.4% of the DFO pool. On an energy basis, ethanol is projected to provide 10.9% of the motor gasoline energy demand, substantially less than the volume contribution, again due to ethanol's lower energy content. Bio-based distillates are projected to provide 5.1% of the DFO energy demand, only slightly less than the volume contribution. The energy contents of biodiesel, renewable diesel, and BTL fuels are only slightly less than crude-based distillate (see Table 4-4). When considering the size of the motor gasoline sector (9.21 MMBD) relative to the DFO sector (4.64 MMBD), the role of ethanol can be seen to be even more substantial in the overall liquid fuels sector. Ethanol alone is projected to comprise over 10% of the volume of fuels consumed in the liquid fuels sector (motor gasoline and DFO); nearly 7% on an energy basis, again, in 2022.

In this EIA projection, 1.69 MMBD, or 25.8 bgy, of biofuels are consumed in 2022. This volume of biofuels consumption falls well short of the RFS mandate of 36 bgy in 2022. By 2030, the projected consumption of biofuels still falls short by nearly 3 bgy, reaching 33.4 bgy.

4.2.2 AEO2009 alternative cases

The EIA does not base its annual outlook of energy markets on a single case. The AEO reports are based on several alternative cases in addition to the reference case. Alternative cases are analogous to the reference case model, but with altered high-level assumptions related to economic growth and world oil prices. The low and high oil price cases "define a wide range of potential price paths, reflecting different assumptions about decisions by OPEC members regarding the preferred rate of oil production and about the future finding and development costs and accessibility of conventional oil resources outside the United States." The low and high economic growth cases "were developed to reflect the uncertainty in projections of economic growth." The alternative cases are used to illustrate and assess the uncertainty and variability in energy market projections resulting from these altered assumptions [162].

In this section, reference and alternative cases of AEO 2009 are presented, along with the updated AEO 2009 reference case, i.e., the *stimulus* case, which was discussed in detail in the previous section. A summary of AEO 2009 cases is provided in Table 4-2. For each case, the table lists the case name, description, and abbreviated identifier used to identify the cases throughout this chapter.

As explained in section 4.2.1, AEO 2009 was released in March 2009 and is based on laws and regulations that were in place in November 2008. The reference case was updated and re-released in April 2009 to reflect the provisions of the federal economic stimulus bill (i.e., ARRA) passed in mid-February. The re-released AEO 2009 reference case, or *stimulus* case, does not include revised alternative cases. Therefore, each of the alternative cases used in this chapter, and listed in Table 4-2, were released with the initial AEO 2009 publication from March 2009.

Table 4-2. The AEO 2009 alternative cases differ based on economic growth and world oil price assumptions [162].

Case	Description	Identifier
Reference	Baseline economic growth (real GDP increases at 2.5%/year on average from 2007-2030), world oil price (world light, sweet crude oil prices reach $130/bbl in 2030, in 2007 dollars), and technology assumptions.	*ref*
Stimulus, or Updated Reference Case	Incorporates ARRA (i.e., economic stimulus bill) provisions into the AEO2009 reference case.	*stimulus*
High Oil Price	World light, sweet crude oil prices are about $200/bbl (2007 dollars) in 2030, compared to $130/bbl in reference case. Other assumptions are the same as reference case.	*hp*
Low Oil Price	World light, sweet crude oil prices are about $50/bbl (2007 dollars) in 2030, compared to $130/bbl in reference case. Other assumptions are the same as reference case.	*lp*
High Economic Growth	Real GDP increases at 3.0%/year on average from 2007-2030. Other assumptions are the same as in the reference case.	*hm*
Low Economic Growth	Real GDP increases at 1.8%/year on average from 2007-2030. Other assumptions are the same as in the reference case.	*lm*

Following the release of the *stimulus* case, additional energy policy changes have been announced, including further changes to CAFE standards and the passing of the Consumer Assistance to Recycle and Save (CARS) Act of 2009, otherwise known as the "cash-for-clunkers" program. The CAFE standards, which were previously updated with the passing of the EISA of 2007, would have required an average fuel economy of 35 mpg in 2020. However, in May 2009, President Obama announced a new national fuel efficiency policy requiring an average fuel economy of 35.5 mpg in 2016. This policy unifies fuel efficiency policies at the federal and state levels, whereas the previous CAFE requirements would have differed from proposed California fuel efficiency standards [163]. The cash-for-clunkers program, passed in June 2009, provided federal funds for consumers to trade in inefficient "clunkers" for more fuel-efficient vehicles. The program was touted as a means for reducing emissions, increasing LDV fleet fuel economy, and stimulating auto sales. Congress ultimately appropriated $3 billion to the program, which resulted in the exchange of nearly 700,000 vehicles in less than one month [164, 165].

These programs, both aimed at increasing average fuel economy of the U.S. automotive fleet, will ultimately impact liquid fuels consumption. Since both were announced after the release of the AEO 2009 *stimulus* case, the projected impacts of these programs are not incorporated in any of the energy market projections listed in Table 4-2, which encompass the most recent AEO cases released by the EIA.

These recent policy changes illustrate the rapidity at which energy markets, and the wider economy, can evolve and change, and the uncertainty inherent in making energy market projections. Despite these recent changes, the AEO 2009 cases should not be viewed as irrelevant. The EIA developed the alternative cases explicitly for this reason. Although the alternative cases do not alter low-level assumptions, like fuel economy standards, such changes can be assessed by examining the impacts of changing high-level assumptions. In the case of increased fuel economy standards, the consumption of oil might be reduced as a result of an increased average fuel efficiency of the LDV fleet. Such a scenario could be analogous, at least qualitatively, to a high oil price case, which causes a reduction in liquid fuels consumption. The quantitative impact of a given program cannot be assessed, but overall qualitative trends can be viewed as similar to the alternative cases. Instead of attempting to revise the AEO projections to incorporate these recent policy changes, the alternative cases can be used to assess broad impacts and altered trends based on changes in overall liquid fuels demand. Since the objective of this chapter is to assess barriers to a biofuels transition, the exact quantitative impacts of these recent energy policy changes should be of minimal concern.

The argument to revise energy market projections each time a new policy or program is announced, or economic indicators change, would seem to invalidate the usefulness of such projections. If these modeling exercises require continuous updates based on short term changes, then it seems that no mid- to long-term projection should be attempted. However, as argued above, the various AEO cases provide a range of energy market futures that can be used to illustrate broad trends based on differing high-level assumptions, such as overall fuel demand.

In the following sections, the alternative cases are presented for the motor gasoline and DFO sectors.

4.2.2.1 Motor Gasoline

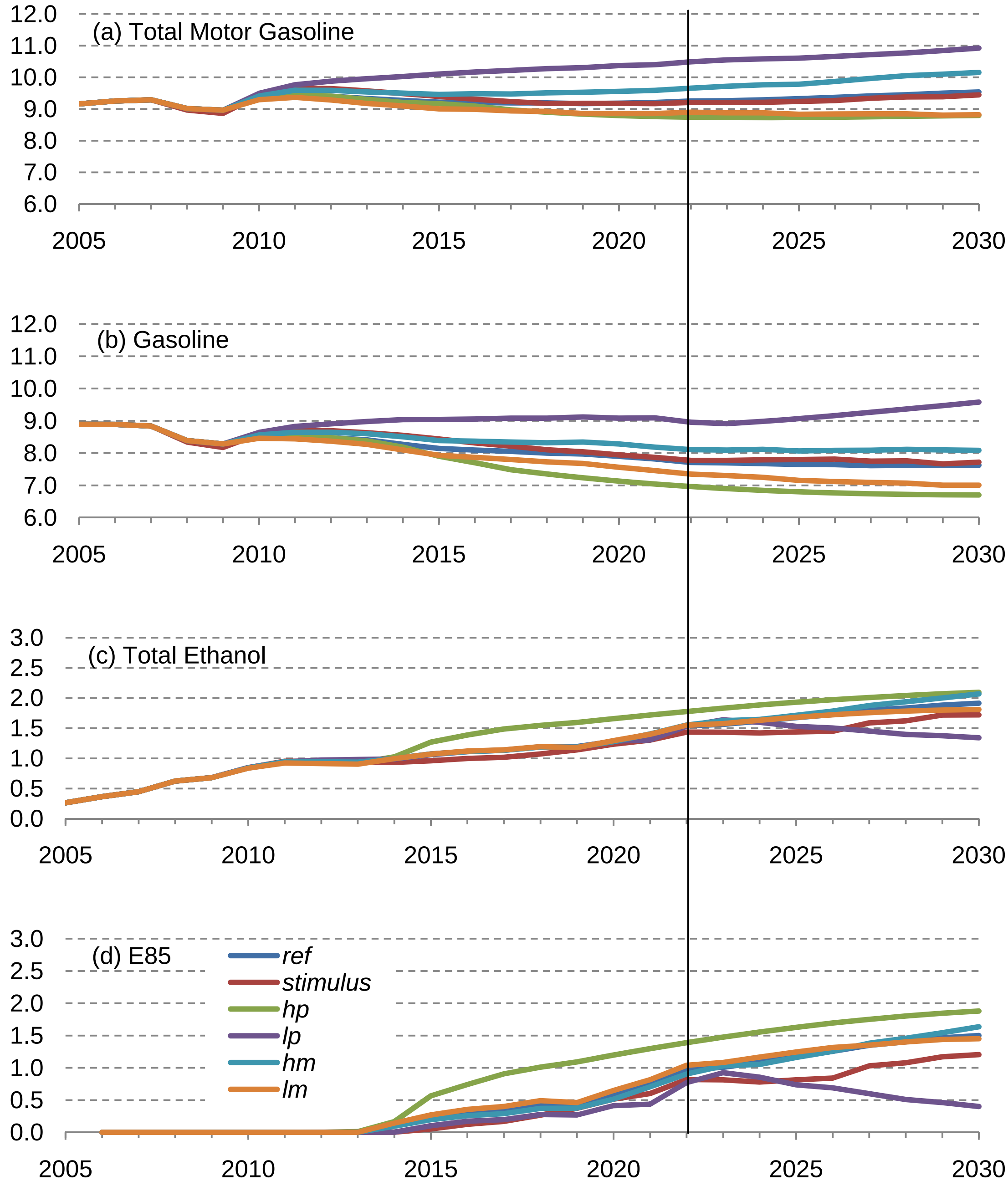
Rather than presenting all data sets from the alternative cases, figures are limited to individual data sets of total motor gasoline, crude-based gasoline, total ethanol, and E85 consumption through 2030. E10 consumption and ethanol consumed as E10 and E85 are omitted. For each data set, the five AEO 2009 cases are plotted along with the *stimulus* case. Data are taken from the Liquid Fuels Supply and Disposition table for each case [2, 159]. Figures 4-5 (a-d) present the motor gasoline projections from 2005 through 2030. Although the full data sets are presented through 2030, the variability through 2022 is of greater interest, as this coincides with the last year of the RFS. The year 2022 is identified by the vertical line crossing through Figures 4-5 (a-d).

Projections of total motor gasoline do not diverge appreciably until 2010. By 2022, the projections differ considerably—the high and low oil price cases, i.e., the *hp* and *lp* cases, range from 8.74 MMBD to 10.49 MMBD, or 134.0 bgy to 160.8 bgy, respectively. This difference represents a significant range of possibilities for the future of the motor gasoline sector through 2022. In the *lp* case, the sector would be required to supply the market with an additional 1.20 MMBD of motor gasoline products compared to 2007. On the other hand, the *hp* case would require the sector to shrink by 0.55 MMBD over the same 15 year period.

In all cases, crude-based gasoline continues to supply the majority of the motor gasoline market. Again, the *hp* and *lp* cases provide the greatest range of potential futures, with consumption of gasoline ranging from 6.96 MMBD to 8.96 MMBD, or 106.8 bgy to 137.3 bgy, respectively. Only the *lp* case shows a steady consumption of crude-based gasoline through 2022; all other cases show a reduction, ensuring that the "peak gasoline" phenomenon is likely to stand as an historical event, rather than a future occurrence.

If the *hp* case is ignored, total ethanol consumption varies by only 0.10 MMBD in the year 2022. However, total ethanol consumption ranges from 1.44 MMBD to 1.78 MMBD, or 22.0 bgy to 27.3 bgy, for the *stimulus* and *hp* cases, respectively. By assuming that the 15 bgy cap on the conventional biofuel category of the RFS is met in each case, then the range in consumption—5.3 bgy—would be based solely on projections of cellulosic ethanol production. With higher oil prices, additional marginal cellulosic ethanol facilities are able to come on line and supply the market. In the *lp* case, total ethanol consumption actually falls after 2023. With depressed oil prices, advanced biofuel technologies would take longer to develop and enter the market to compete economically with crude-based fuels and conventional biofuels.

E85 consumption varies widely in 2022, but, like total ethanol consumption, the *hp* case produces the greatest growth. In 2022, E85 consumption ranges from 0.77 MMBD to 1.39 MMBD, or 11.8 to 21.3 bgy, for the *lp* and *hp* cases, respectively. The high oil price yields a near doubling in E85 consumption compared to the low oil price assumption. By 2030, the *hp* case projects the consumption of E85 to be over four times that of the *lp* case. This wide range might seem at odds with the relatively small range in total ethanol consumption. However, ethanol and E85 consumption cannot be examined in isolation from total motor gasoline or crude-based gasoline consumption. In addition to the increased total ethanol consumption with higher oil prices, crude-based gasoline and total gasoline consumption fall. Therefore, ethanol must be blended increasingly as E85, rather than as E10, since less gasoline is available for blending. So, as high prices allow ethanol to capture market share from crude-based gasoline, total consumption also falls, requiring greater penetration of E85, or other high-level blends.



Figures 4-5 (a-d). The AEO2009 cases and *stimulus* case projections of (a) Total Motor Gasoline, (b) Crude-Based Gasoline, (c) Total Ethanol, and (d) E85 consumption illustrate the wide range of potential futures in the motor gasoline sector resulting from varied high-level assumptions. The vertical axes are in units of MMBD of product supplied.

4.2.2.2 DFO

Like the motor gasoline projections, figures are limited to 4 data sets: total distillate, crude-based distillate, non-crude-based distillate, and bio-based distillate consumption through 2030. Biodiesel consumption is omitted. For each data set, the five AEO 2009 cases are plotted along with the *stimulus* case. Data are taken from the Liquid Fuels Supply and Disposition table for each case [2, 159]. Figures 4-6 (a-d) present the DFO projections from 2005 through 2030. Again, the variability through 2022 is of greatest interest, as this coincides with the last year of the RFS. Like Figures 4-5 (a-d), the year 2022 is identified by the vertical line crossing through Figures 4-6 (a-d).

Total distillate consumption does not vary appreciably until after 2010. By 2022, the low and high economic cases, i.e., the *lm* and *hm* cases, range from 4.34 MMBD to 5.07 MMBD, or 66.5 bgy to 77.8 bgy, respectively. In all cases, the total demand for distillate products is projected to increase. The *hm* case would require an additional 0.88 MMBD of distillate products compared to 2007.

Crude-based distillate maintains a substantial share of total distillate consumption through 2022, supplying over 90% of the market volume. Again, the *lm* and *hm* cases provide the greatest variation in potential futures, with crude-based distillate consumption ranging from 3.96 MMBD to 4.69 MMBD, or 60.7 bgy to 71.9 bgy, respectively. All cases project increasing demand for crude-based distillate products, except for the *hp* and *lm* cases, which show small reductions in demand. The *hm* case would call for an additional 0.52 MMBD of crude-based distillate over 2007 demand.

This trend differs substantially from the projected future of stagnation or contraction of demand for crude-based gasoline products. Gasoline is projected to maintain no more than 85% of the volume in the motor gasoline sector, and could fall below 80%. Oil refiners would be faced with the need reconfigure operations to provide for an increasing output of distillates, or at least a growing percentage of distillate output relative to gasoline in their product slate. Historically, U.S refiners have optimized operations to maximize gasoline consumption. This trend stands in contrast to European refiners, where refinery product slate is configured to optimize distillate production. Demand for distillate fuels has grown to such an extent in Europe that surplus gasoline production is exported to the U.S. As the U.S. shifts demand from gasoline to distillate fuels, both U.S. and European refiners could be impacted. European refiners could face a dwindling export market for gasoline [166].

By comparing the range of projections in total distillate to total motor gasoline consumption, an interesting difference becomes apparent. Oil price assumptions (i.e., the *lp* and *hp* cases) have a greater impact on total motor gasoline (and crude-based gasoline) consumption, whereas economic assumptions (i.e., the *lm* and *hm* cases) have a greater impact on total distillate (and crude-based distillate) consumption. According to the EIA projections, demand in the DFO sector is heavily influenced by economic activity. Since distillate fuels are used overwhelmingly to power vital sectors of the economy (e.g., shipping and transportation of commodities and goods, construction, agriculture, etc), an increase or decrease in economic activity would result in an increase or decrease in distillate demand. On the other hand, demand in the motor gasoline sector is influenced more by oil prices. Since motor gasoline products are used primarily to fuel personal transportation, an increase or decrease in oil prices could serve to alter consumer driving habits and decrease or increase motor gasoline demand.

Consumption of non-crude-based distillate—distillate fuels derived from non-crude feedstocks—is projected to grow in all cases. The *lp* and *hp* cases result in substantial variation in consumption, ranging from 0.19 MMBD to 0.61 MMBD, or 2.9 bgy to 9.3 bgy, respectively. All cases represent significant growth from a market of 360 mgy in 2007. The *hp* case requires the supply of non-crude-based distillate fuels to increase by nearly 2,500% from 2007 through 2022. If the *hp* and *lp* cases are ignored, the remaining cases project very similar growth, increasing to approximately 0.38 MMBD, or 5.8 bgy, in 2022.

In 2022, bio-based distillate consumption ranges from 0.14 MMBD to 0.31 MMBD, or 2.2 to 4.8 bgy, respectively. Bio-based distillate is projected to supply only

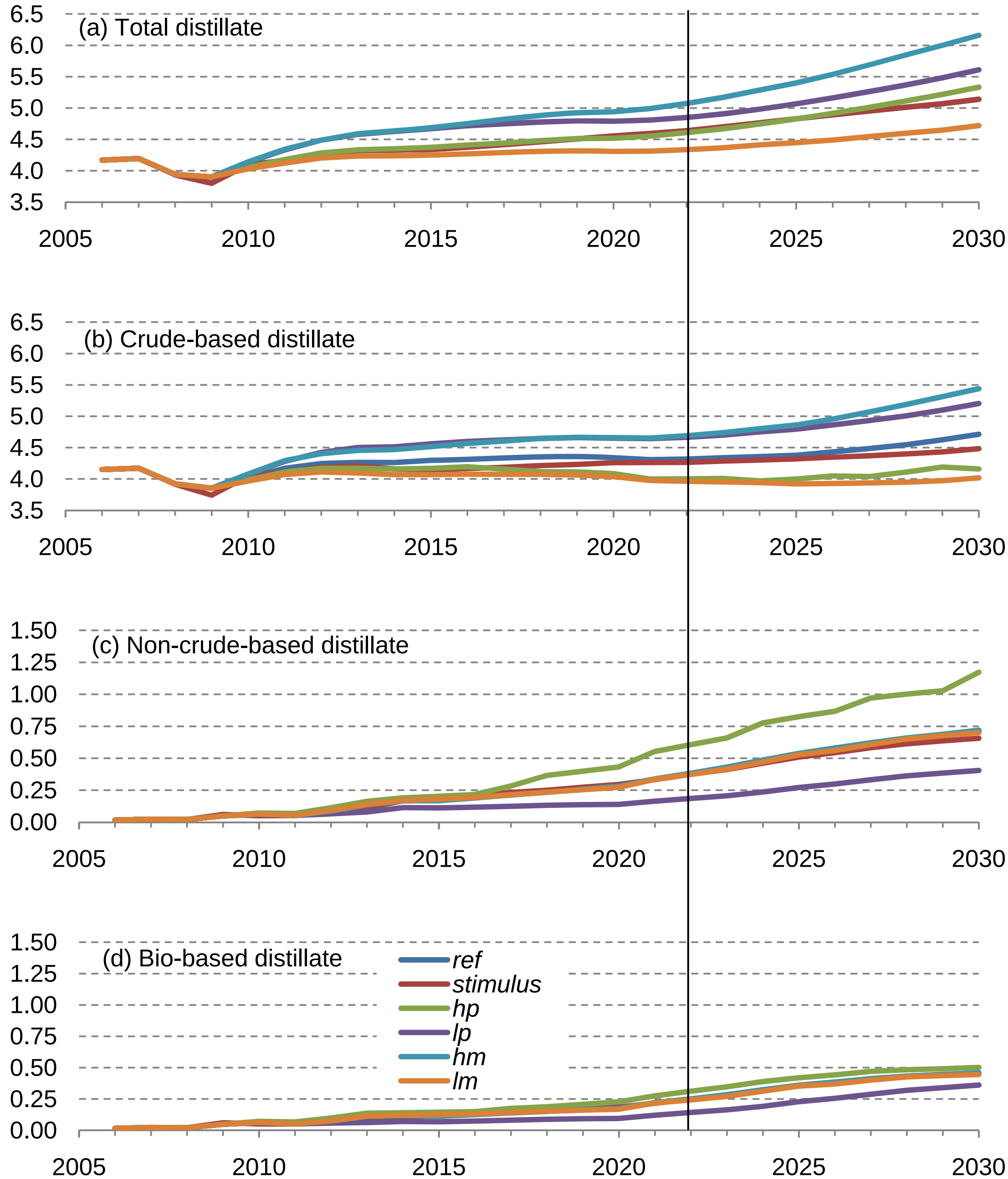
3% to 7% of total distillate consumption on a volume basis. In contrast, ethanol is projected to capture 15% to 20% of the motor gasoline pool, again, on a volume basis. Despite the lower energy content of ethanol compared to crude-based gasoline, the gasoline substitute is projected to penetrate the market much more than bio-based substitutes in the DFO sector. In addition, when considering the size of the motor gasoline sector relative to the DFO sector, ethanol is projected to maintain its role as the nation's primary biofuel consumed in the liquid fuels sector. On a volume basis, consumption of bio-based distillates is projected to be 10% to 20% of total ethanol consumption in 2022.

Note that the greatest variability in total distillate and crude-based distillate consumption results from the altered economic assumptions, whereas the oil price assumptions have the greatest impact on consumption of non-crude-based and bio-based distillates. The impact of economic activity on total distillate demand was explained above. For the alternative distillates, oil price assumptions drive growth since many of the alternatives, e.g., biodiesel, BTL, coal-to-liquids (CTL), etc, serve as marginal supplies. They are relatively expensive to produce. In order for these fuels to supply a substantial portion of the DFO market, oil prices need to climb to a point where the alternative technologies can be deployed and fuel production facilities can compete economically with conventional, crude-based fuels. The level of economic activity has little to no impact on the consumption of these fuels, as evidenced by the lack of variability between the economic cases and the reference and *stimulus* cases in Figures 4-6 (c, d).

Total liquid fuels consumption is projected to increase from 13.48 MMBD, or 206.7 bgy, in 2007 to a range in 2022 of 13.59 MMBD to 14.32 MMBD, or 208.3 bgy to 219.6 bgy, for the *lm* and *hm* cases, respectively. This range represents a growth of 100 MBD to 1 MMBD over a 15 year time period. In all cases, biofuels consumption is projected to fall short of the 36 bgy mandate in 2022, ranging from 25.8 bgy to 28.4 bgy, for the *lp* and *hp* cases, respectively. In 2030, all but the *lp* case are projected to slightly exceed 36 bgy of biofuels consumption.

Again, the oil price assumptions cause substantial variability in motor gasoline and biofuels consumption through 2022. This variability proves useful in the development of biofuels transition scenarios, presented in section 4.4. Aside from the *stimulus* case, only the alternative oil price cases are used as inputs to the LiFTrans model. There are several reasons for moving forward with the *hp* and *lp* cases, which provide a greater range of total motor gasoline consumption. First, as explained above, ethanol is expected to continue its prominent role in the biofuels industry, with bio-based distillate consumption projected to fall well short of ethanol consumption in the foreseeable future. Second, ethanol is consumed in the motor gasoline sector, which will continue to be much larger than the DFO sector. Third, ethanol presents many unique challenges due to its fuel properties, whereas bio-based distillates are more easily integrated into the existing DFO supply and infrastructure.

This chapter is focused on developing biofuel transition scenarios to reveal barriers to a biofuels transition. Therefore, due to the reasons just explained, greater emphasis is placed on the barriers facing an increased penetration of ethanol in the motor gasoline sector. Before the biofuel transition scenarios are presented, the model used to develop the scenarios is described.



Figures 4-6 (a-d). The AEO2009 cases and *stimulus* case projections of (a) Total distillate, (b) Crude-based distillate, (c) Non-crude-based distillate, and (d) bio-based distillate consumption illustrate the wide range of potential futures in the DFO sector resulting from varied high-level assumptions. The vertical axes are in units of MMBD of product supplied.

4.3 Liquid fuels transition (LiFTrans) model

The Liquid Fuels Transition (LiFTrans) model was developed to explore potential pathways that could be followed in the liquid fuels sector to meet the requirements of the RFS through 2022. The model creates transition scenarios based on a limited set of user inputs. Scenario results include annual consumption of biofuels (e.g., ethanol, bio-based distillate), crude-based fuels, and total liquid fuels consumption for the motor gasoline and DFO sectors. Scenarios developed with the model can be presented in a format analogous to Figures 4-1 through 4-4 in section 4.2. The overall structure and individual components (e.g., source data, user inputs, calculations, outputs) of the model are discussed in detail below. Assumptions related to each component of the model are stated explicitly. Implementation of the model in a spreadsheet application is also briefly discussed. Results of the model are not included in this section; the model runs, or scenarios, and their accompanying results are presented in section 4.4

4.3.1 Model structure

Figure 4-7 illustrates the basic components of the LiFTrans model. The model uses two primary demand, or fuel consumption, functions: total liquid fuels and biofuels. These demand functions are used for both the motor gasoline (MoGas) and DFO portions of the model. As explained in section 4.2, the total liquid fuels demand functions are derived from the AEO 2009 cases. The RFS program, which is assumed to be the primary driver of biofuels consumption through 2022, serves as the biofuels demand function. However, these data sources are not directly fed into the model. Several variables were created to increase model flexibility, allowing the user to alter assumptions and develop a range of alternative transition scenarios. These include the specification of annual biofuel volumes (by fuel type), motor gasoline blend limit, and total liquid fuels demand (from a set of AEO cases). In the following sections, data sources, user inputs, calculation procedures, model output, and model implementation are discussed.

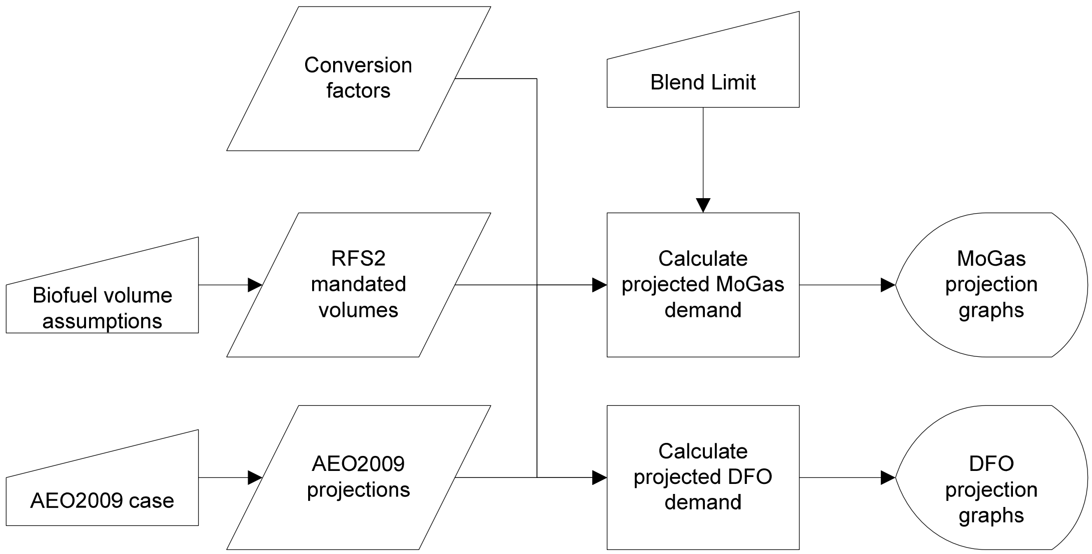


Figure 4-7. The flowchart illustrates the basic components (inputs, data, processes, outputs) of the LiFTrans model. Note that motor gasoline has been denoted as 'MoGas'.

4.3.2 Data sources

4.3.2.1 RFS2 mandated volumes

Table 4-3 shows the annual biofuel volumes mandated by the RFS program, along with a control case used by the EPA to analyze one plausible pathway to meeting the mandate.[43] The program specifies annual volumes of total renewable fuel (i.e., biofuel), and further specifies volumes of advanced biofuels—cellulosic biofuel, biomass-based diesel, and other advanced biofuel. As proposed in the RFS2 Notice of Proposed Rulemaking (NPRM), each biofuel category contributes on a per-gallon basis, i.e., the

[43] The control case was developed and used by EPA analysts in the RFS2 Draft Regulatory Impact Assessment (DRIA).

equivalence values defined in the original RFS program will no longer be used [25]. The EPA control case in Table 4-3 actually falls just short of the mandated ‘other advanced biofuel’ category from 2011 through 2022. For an explanation of this shortfall in the EPA control case, the reader is referred to section 1.2.5 of the EPA RFS2 DRIA document [25].

The mandated biofuel volumes serve as a guide for the model user when developing a biofuel demand function. The biofuel demand function is discussed further in section 4.3.3 below.

4.3.2.2 AEO2009 projections

Total liquid fuels demand functions are derived from the AEO 2009 cases presented in section 4.2. The motor gasoline demand function is derived from the Liquid Fuels Supply and Disposition tables of the AEO 2009 cases [2, 159]. Total motor gasoline supply includes both crude-based gasoline and ethanol, i.e., all liquid fuels consumed in gasoline-powered equipment. However, only total motor gasoline demand through 2022 is used as an input to the model. The DFO demand function is also derived from the Liquid Fuels Supply and Disposition tables of the AEO 2009 cases [2, 159]. DFO supply includes crude-based DFO, biodiesel, and various xTL (biomass (B)-, coal (C)-, and gas (G)-to-liquid) fuels. DFO is specified, by the EIA, as fuel oil nos. 1, 2, and 4. These distillate fuels are used primarily in diesel-powered equipment (excluding air transportation) and heating oil applications. Only total distillate demand through 2022 is used as an input to the model.

The calculation procedures for determining the total MoGas and DFO demand functions from the AEO2009 cases are explained in section 4.3.4.

Table 4-3. The EPA RFS2 DRIA control case serves as an example of one pathway to meeting the RFS mandate. All fuel values are in billion gallons per year (bgy) [25].

	Advanced Biofuel										Non-Advanced Biofuel		
	Cellulosic Biofuel	(mandate)	Biomass-Based Diesel			(mandate)	Other Advanced Biofuel			(mandate)			(mandate)
Year	Cellulosic Ethanol		FAME Biodiesel	Non-Co-processed Renewable Diesel	sum		Co-processed Renewable Diesel	Imported Ethanol	sum		Corn Ethanol	Total Renewable Fuel	
2008		0.00				0.00				0.00			9.00
2009	0.00	0.00	0.50	0.00	0.50	0.50	0.00	0.50	0.50	0.10	9.85	10.85	11.10
2010	0.10	0.10	0.64	0.01	0.65	0.65	0.01	0.29	0.30	0.20	11.55	12.60	12.95
2011	0.25	0.25	0.77	0.03	0.80	0.80	0.03	0.16	0.19	0.30	12.29	13.53	13.95
2012	0.50	0.50	0.96	0.04	1.00	1.00	0.04	0.18	0.22	0.50	12.94	14.66	15.20
2013	1.00	1.00	0.94	0.06	1.00	1.00	0.06	0.19	0.25	0.75	13.75	16.00	16.55
2014	1.75	1.75	0.93	0.07	1.00	1.00	0.07	0.36	0.43	1.00	14.40	17.58	18.15
2015	3.00	3.00	0.91	0.09	1.00	1.00	0.09	0.83	0.92	1.50	15.00	19.92	20.50
2016	4.25	4.25	0.90	0.10	1.00	1.00	0.10	1.31	1.41	2.00	15.00	21.66	22.25
2017	5.50	5.50	0.88	0.12	1.00	1.00	0.12	1.78	1.90	2.50	15.00	23.40	24.00
2018	7.00	7.00	0.87	0.13	1.00	1.00	0.13	2.25	2.38	3.00	15.00	25.38	26.00
2019	8.50	8.50	0.85	0.15	1.00	1.00	0.15	2.72	2.87	3.50	15.00	27.37	28.00
2020	10.50	10.50	0.84	0.16	1.00	1.00	0.16	2.70	2.86	3.50	15.00	29.36	30.00
2021	13.50	13.50	0.83	0.17	1.00	1.00	0.17	2.67	2.84	3.50	15.00	32.34	33.00
2022	16.00	16.00	0.81	0.19	1.00	1.00	0.19	3.14	3.33	4.00	15.00	35.33	36.00

4.3.2.3 Conversion factors

The lower heating values (LHV) of the fuels represented in the model are listed in Table 4-4 (in Btu/gallon). Values are derived from those published in the Greenhouse Gas, Regulated Emissions, and Energy Use in Transportation (GREET) model [167]. To simplify calculations, and to avoid the need to further specify fuel categories, the following assumptions are made with regards to the heating values.

Gasoline (crude-based) - Reformulated and conventional gasolines have slightly different heating values. To avoid the specification of these types of gasoline, an averaged value is used. RFG comprises approximately one-third of the gasoline pool, based on historical data from the EIA [42]. Therefore, the LHV for crude-based gasoline is weighted as follows:

$$LHV_{gasoline} = \frac{1}{3} \times LHV_{RFG} + \frac{2}{3} \times LHV_{CG}$$

DFO (crude-based) - DFO is comprised of several types of distillate, distinguished primarily by sulfur content. GREET includes two categories: conventional diesel and low-sulfur diesel. Although distillate could be further specified (e.g., conventional, LSD, ULSD), the LHV for crude-based DFO was weighted based on these two values. The weighting is based on historical data from the EIA, which shows that conventional diesel (>500 ppm) makes up just under one-fifth of the DFO pool. Regardless of this weighting, the LHVs differ by less than 1,000 Btu/gallon. The LHV for DFO is weighted as follows:

$$LHV_{DFO} = \frac{1}{5} \times LHV_{CD} + \frac{4}{5} \times LHV_{LSD}$$

Liquids from biomass - This category of fuel includes renewable diesel (RD) and BTL (or FT diesel). GREET provides one value for BTL, but provides two values for RD based on a SuperCetane RD and a UOP-HDO RD. The BTL and UOP-HDO RD heating values are nearly equivalent, and are averaged for the liquids from biomass LHV:

$$LHV_{RD/BTL} = \frac{1}{2} \times LHV_{BTL} + \frac{1}{2} \times LHV_{RD\ (UOP\text{-}HDO)}$$

Table 4-4. Lower-heating values are derived from the GREET model [167].

Fuel	LHV [Btu/gal]
gasoline	115,261
ethanol	76,330
diesel (DFO)	129,280
biodiesel	119,550
liquids from biomass (RD/BTL)	123,279
renewable gasoline	115,983

4.3.3 User inputs

4.3.3.1 AEO2009 case

For MoGas and DFO demand, any projection could be used. As explained above, the demand functions are derived from the AEO 2009 cases. The AEO 2009 *stimulus* case was used as a starting point to implement the model. In the current model implementation, the user can select amongst 6 different AEO cases: AEO 2009 reference, high- and low-oil price, high- and low-economic growth, and revised reference case based on the economic stimulus, i.e., *ref*, *hp*, *lp*, *hm*, *lm*, and *stimulus*, respectively.[44] The reference case serves as the default demand input.

Although these cases provide the user with a range of total demand, the model is restricted to EIA analysts' vision of the future. To allow for maximum flexibility, the model could be implemented to allow for user-specified demand functions for the motor gasoline and DFO sectors. However, since the AEO projections are widely referenced and utilized for energy planning, they set useful bounds on the demand function. Scenarios can be compared to actual AEO case projections to investigate the impacts that other inputs have on the projections (e.g., the impact of varying the ethanol blend limit).

4.3.3.2 Biofuel volume assumptions

For each mandated category of biofuel, several types of biofuels could potentially be used to meet the mandate. Table 4-3, as mentioned previously, shows the control case projection used by EPA analysts in the RFS2 DRIA. In this control case, the majority of the mandate is met with ethanol—cellulosic ethanol, imported Brazilian sugar-cane ethanol, and corn ethanol. The model allows the user to alter the types and quantities of fuels consumed on an annual basis, again, through 2022. For example, the cellulosic biofuel mandate could be partially met with cellulosic diesel (i.e., BTL), rather than exclusively cellulosic ethanol, as in the EPA control case. The RFS requirements do not serve as a strict input; rather, they serve as a guide for the user when developing a biofuel demand function. The user is not obligated to develop a demand function that meets all requirements of the RFS mandate. When the user-supplied biofuel demand function fails to meet the annual volume requirements for each biofuel category and in total, the model notifies the user. The implementation of this aspect of the model is discussed further in section 4.3.6.

For each EPA-defined category of biofuel, the user must enter the annual volumes of fuels consumed. For example, for cellulosic biofuel, the user can specify annual volumes of cellulosic ethanol and/or cellulosic diesel (i.e., BTL) consumed in the MoGas

[44] See Table 4-2 for a description of the alternative cases.

and DFO sectors, respectively. Annual volumes must be entered in billion gallons per year.

This model component could be updated to include a wider range of fuels (e.g., biobutanol) and flexibility with the penetration rate of E85 (i.e., allowing for the E85 market to develop prior to reaching the blend limit).

4.3.3.3 Blend limit

This component of the model is a single variable used to specify the ethanol blend limit in the motor gasoline sector. The blend limit is the maximum percentage of ethanol that can be blended into conventional and reformulated gasolines (CG and RFG, respectively) for use in non-flex-fuel vehicles. The CAA currently limits the blend limit to 10% ethanol.[45] To incorporate the increasing volumes of ethanol into the gasoline pool, many ethanol-advocates are pushing for this limit to be increased to 15-20% [25, 168]. Therefore, the model was designed to allow the user to specify any value greater than or equal to 10% for the blend limit variable (up to 100%).

4.3.4 Model calculations

4.3.4.1 Calculate projected MoGas demand

The objective of this component is to calculate the annual volumes of total motor gasoline, crude-based gasoline, ethanol, motor gasoline (crude-based gasoline plus ethanol not blended as E85), and E85 from 2007 through 2022. The volumes of ethanol used in motor gasoline (e.g., E10) and E85 are also determined. Inputs include the assumed annual volumes of total ethanol used to meet the mandate, total MoGas demand, the blend limit, and heating values.

It is assumed that there is negligible demand for E85 until the blend limit is reached. Based on information from the EIA [2], E85 is represented with a seasonally-

[45] Again, the ethanol blend limit is discussed further in section 4.4.2.

averaged content of 74% ethanol by volume.[46] Due to the differences in energy content between gasoline and ethanol, an annual total motor gasoline energy demand is needed (i.e., the total motor gasoline demand function). This demand is derived from the user-specified AEO projection as follows:[47]

TMG [MMBtuD] = E [MMBtuD] + G [MMBtuD]

where:

G [MMBtuD] = G [MMBD] × 42 gal/bbl × LHV_G [Btu/gal]

E [MMBtuD] = *E* [MMBD] × 42 gal/bbl × LHV_E [Btu/gal]

G [MMBD] = TMG [MMBD] – *E* [MMBD]

TMG [MMBD] = *E85* [MMBD] + *MG* [MMBD]

E (Ethanol), *E85*, and *MG (Motor Gasoline)* [MMBD] are inputs from the AEO 2009 projections.

The total MoGas energy demand (from above) and assumed ethanol volume (from the biofuel demand function) are then used to determine the projection. The user-specified ethanol volume is converted to an ethanol energy demand as follows:

E [MMBtuD] = E [MMBD] × 42 gal/bbl × LHV_E [Btu/gal]

where:

E [MMBD] = E (user specified) [bgy] × (10^3 / 42 gal/bbl / 365 D/y)

To determine the crude-based gasoline energy demand, the ethanol energy demand is subtracted from the total MoGas energy demand:

G [MMBtuD] = TMG [MMBtuD] – E [MMBtuD]

[46] The volume of ethanol in E85 varies with the season to address cold start issues.
[47] Data series are represented with the following variables: Total Motor Gasoline (TMG), Ethanol (E), crude-based Gasoline (G), E85 (E85), Motor Gasoline, e.g., E10 (MG), Ethanol in E85 (EE85), Ethanol in Motor Gasoline (EMG), and blend limit (xx). Also, MMBtuD denotes million Btu per day.

The volume of crude-based gasoline can now be determined:

$$G\ [\text{MMBD}] = G\ [\text{MMBtuD}] / 42\ \text{gal/bbl} / LHV_G\ [\text{Btu/gal}]$$

In order to determine the allocation of ethanol between motor gasoline and E85, recall the assumption that all ethanol is allocated to motor gasoline until the user-specified blend limit (xx) is reached. Using the known volumes of ethanol and crude-based gasoline, the following set of equations are solved to determine the volumes of E85 and motor gasoline:

$$E = xx \times MG + 0.74 \times E85$$

$$G = (1 - xx) \times MG + 0.26 \times E85$$

The above equations are solved for motor gasoline and E85 volumes:

$$MG = \frac{(E - 0.74 \times E85)}{xx}$$

$$E85 = \frac{G - \left(\frac{1}{xx} - 1\right) \times E}{0.26 - 0.74 \times (\frac{1}{xx} - 1)}$$

These equations assume that there is sufficient volume of ethanol, relative to the volume of crude-based gasoline, to have both motor gasoline and E85 supplied in the MoGas sector. When ethanol volumes are insufficient relative to crude-based gasoline, all ethanol is allocated to produce low-level motor gasoline blends. Finally, the ethanol allocated to each type of fuel, motor gasoline and E85, is determined:

$$EE85\ [\text{MMBD}] = 0.74 \times E85\ [\text{MMBD}]$$

$$EMG\ [\text{MMBD}] = E\ [\text{MMBD}] - EE85\ [\text{MMBD}]$$

The blend percentage in motor gasoline can be determined assuming an average blend-level nationwide:

xx = EMG [MMBD] / Exx [MMBD]

These calculations are completed for each year in the projection through 2022.

The energy-volume conversions assume that FFVs are not designed to optimize fuel consumption when fueled with ethanol-blends, e.g., E85. Engines can be designed (e.g., increase the compression ratio) to take advantage of the higher octane of ethanol to improve fuel economy [169-171].

4.3.4.2 Calculate projected DFO demand

The objective of this component is to calculate the annual volumes of total distillate fuel oil (DFO), crude-based DFO, biodiesel, and liquids from biomass from 2007 through 2022. Inputs include the assumed annual volumes of bio-based distillate used to meet the RFS2 mandate, total DFO demand, and heating values.

Due to the differences in energy content between the various fuels, an annual total DFO energy demand is needed (i.e., the total distillate demand function). This demand is derived from the user-specified AEO 2009 projection as follows:[48]

TDFO [MMBtuD] = DFO [MMBtuD] + BD [MMBtuD] + *xTL* [MMBtuD]

where:[49]

DFO [MMBtuD] = DFO [MMBD] × 42 gal/bbl × LHV_{DFO} [Btu/gal]

BD [MMBtuD] = *BD* [MMBD] × 42 gal/bbl × LHV_{BD} [Btu/gal]

xTL [MMBtuD] = *xTL* [MMBD] × 42 gal/bbl × LHV_{xTL} [Btu/gal]

DFO [MMBD] = *DFO* [MMBD] – *BD* [MMBD] – *xTL* [MMBD]

xTL [MMBD] = *GTL* [MMBD] + *CTL* [MMBD] + *BTL* [MMBD]

[48] Data series are represented with the following variables: Total DFO (TDFO), crude-based DFO (DFO), Biodiesel (BD), non-crude-based DFO (NDFO), bio-based DFO (BDFO), and renewable diesel/biomass-to-liquid (RD/BTL).

[49] LHV_{xTL} is assumed to be equivalent to $LHV_{RD/BTL}$.

DFO (Distillate Fuel Oil), *BD (Biodiesel)*, *GTL (Liquids from Gas)*, *CTL (Liquids from Coal)*, and *BTL (Liquids from Biomass)* [MMBD] are inputs from the AEO 2009 projections.

The total DFO energy demand (from above) and assumed DFO substitute volumes (from the biofuel demand function) are then used to determine the projection. The CTL volumes are taken directly from the user-specified AEO 2009 case. The user-specified biofuel volumes are converted to energy demands as follows:

BD [MMBtuD] = BD [MMBD] × 42 gal/bbl × LHV_{BD} [Btu/gal]

RD/BTL [MMBtuD] = RD/BTL [MMBD] × 42 gal/bbl × $LHV_{RD/BTL}$ [Btu/gal]

where:

BD [MMBD] = BD (user specified) [bgy] × (10^3 / 42 gal/bbl / 365 D/y)

RD/BTL [MMBD] = RD/BTL (user specified) [bgy] ×(10^3 / 42 gal/bbl / 365 D/y)

To determine the crude-based DFO energy demand, the DFO substitute energy demands are subtracted from the total DFO energy demand:[50]

DFO [MMBtuD] = TDFO [MMBtuD] – BD [MMBtuD] – xTL [MMBtuD]

where:

xTL [MMBtuD] = RD/BTL [MMBtuD] + *CTL* [MMBtuD]

The volume of crude-based DFO can now be determined:

DFO [MMBD] = DFO [MMBtuD] / 42 gal/bbl / LHV_{DFO} [Btu/gal]

The non-crude-based DFO and bio-based volumes can then be determined:

NDFO [MMBD] = BD [MMBD] + xTL [MMBD]

BDFO [MMBD] = BD [MMBD] + RD/BTL [MMBD]

[50] *CTL (Liquids from Coal)* demand is taken from the AEO 2009 projections.

These calculations are completed for each year in the projection through 2022.

The current implementation of the model does not include a blend limit for the DFO sector. Such a limit would only apply to the blending of biodiesel in the DFO pool and not to synthetic (xTL) fuels. Biodiesel, an ester (e.g. fatty-acid methyl ester), is an oxygenated fuel having different properties than hydrocarbons. As discussed in section 4.2.1.2, the distillate fuel specifications, ASTM D975 and D396, were recently updated to allow for blending with up to 5% biodiesel by volume. These specifications require that the biodiesel blendstock (B100) meets the ASTM D6751 specification prior to blending, and that the resulting blend, up to B5, meets all aspects of D975 or D396. D975 is the specification for diesel fuel oils; D396 covers fuel oils (e.g. home heating) [161]. Current production of biodiesel is well below a hypothetical nationwide 5% blend, and projections by the EPA show that oil-based feedstocks will be limited in the foreseeable future [25], limiting the production of biodiesel below such a limit. Regardless, the model could be altered to allow for greater volumes of biodiesel and the ability to implement a blend limit. Since D975 and D396 allow for blends up to B5, such blends can be treated as standard crude-based DFO in the fuel infrastructure. For higher blends, manufacturers have various limitations on the use of biodiesel; some OEMs limit use to B5, while others allow for limited use of blends up to B20, with a minority of manufacturers allowing for very restricted use of neat biodiesel (B100) [104]. The synthetic fuels are not burdened with this issue since they are chemically similar to crude-based DFO hydrocarbons, and exhibit some properties that are more advantageous (e.g., higher cetane, ultra-low sulfur content, etc) [172].

4.3.5 Model output and results

Results can be presented in a format analogous to Figures 4-1 through 4-4 in section 4.2. For the motor gasoline component, the output can be displayed graphically in a time series showing the following fuel volumes (in MMBD): Total MoGas, Gasoline (crude-based), E10, E85, Ethanol, and Ethanol in E10 and E85. Likewise, for the DFO component, the output includes the following fuel volumes (in MMBD): Total DFO, crude-based DFO, Biodiesel, Bio-based DFO, and Non-crude-based DFO. Example results from the model are not included in this section. The actual model runs, or scenarios, and their accompanying results are presented in section 4.4.

4.3.6 Model implementation

The LiFTrans model is currently implemented as a spreadsheet model in Microsoft Excel. All data sources, user input interfaces, calculations, and outputs are contained in a single workbook. For each model run, the source workbook is saved as a new file, allowing the user to modify inputs while preserving the default model settings in the source workbook.

Data sources (AEO 2009 projection data, RFS mandated biofuel volumes, conversion factors) are organized in individual worksheets as data tables. Data from the Liquid Fuels Supply and Disposition table of each AEO 2009 case are organized in 6 worksheets. User input is solicited through individual worksheet cells. The AEO case is specified through a single cell, requiring the user to enter a number (0-5) to specify the desired case (*ref*, *stimulus*, *hp*, *lp*, *hm*, and *lm*, respectively). If the user enters a number greater than 5, or less than 0, the model defaults to the *ref* case. The biofuel volumes are also entered in worksheet cells, but the user must specify annual volumes from 2009 through 2020 for a range of fuel types. Within each EPA-defined fuel category, the user can select from several biofuels, e.g., cellulosic biofuel is divided into cellulosic ethanol and cellulosic diesel (i.e., BTL). The user may specify any volume for a given biofuel in a given year, regardless of the RFS volume requirements. However, the spreadsheet notifies the user when annual requirements for a given fuel category, or total biofuel requirement, are not met. This notification is made through a change in cell color via conditional formatting. The ethanol blend limit is inputted in a single cell as a numeric value from 10 up to 100, representing the maximum allowable percentage of ethanol in motor gasoline. If the user enters a value outside of this range, the model defaults to 10%.

Once all inputs have been supplied by the user, the results are ready to be viewed. The time series of fuel volumes are provided as data tables and figures. Several pre-made figures with variable time frames and sets of data series are available for immediate review. Scenario results can be viewed in combination with historical trends in the liquid fuels sector as well. Due to limitations in Microsoft Excel's plotting functions, data labels and axes often need to be readjusted when inputs are altered.

The simplicity of the LiFTrans model allows for a straightforward implementation in a single Excel workbook. Despite this simplicity, the model allows for a wide range of biofuel transition scenarios to be developed. Scenarios developed with this model are presented in the next section.

4.4 BIOFUEL TRANSITION SCENARIOS

Using the LiFTrans model, a set of scenarios was developed. Most scenarios utilize the AEO 2009 *stimulus* case for the total liquid fuels demand functions; the *hp* and *lp* cases are the only other projections that serve as inputs to this set of scenarios. Although the biofuel demand function is defined differently for several of the scenarios, each of the assumed biofuel consumption trends meets the annual volume requirements of the RFS. All biofuels are assumed to meet or exceed the GHG reduction requirements specified for each fuel category, as dictated by the RFS program. For example, cellulosic ethanol or cellulosic diesel could be used to satisfy the cellulosic biofuel mandate as substitutes for gasoline or diesel, respectively. Both fuels are assumed to reduce lifecycle GHG emissions by at least 60% compared to the lifecycle emissions of 2005 petroleum baseline fuels displaced by the cellulosic biofuel, such as gasoline or diesel [25].

Table 4-5 lists the transition scenarios with brief descriptions of each. The scenarios are discussed in detail in the following subsections. For each scenario, the model inputs (and accompanying assumptions) and results are presented. Scenario 1 serves as a base case that complies with the RFS mandate and satisfies the projected liquid fuels demand in the AEO 2009 *stimulus* case. The remaining scenarios build off of this base case with altered assumptions (i.e., altered model inputs).

Table 4-5. The following transition scenarios were developed with the LiFTrans model.

Scenario	Description
1	RFS compliance base case
2	Increased ethanol blend limit
3	Increased consumption of biofuels in the DFO sector
4	Increased consumption of non-ethanol biofuels in the MoGas sector
5	Variable liquid fuels demand (i.e., increased/decreased liquid fuels demand)

The model assumptions and inputs used to develop these scenarios could be combined in numerous additional combinations, creating an ever lengthening list of narrowly-defined transition scenarios. For instance, a decreased total liquid fuels demand scenario (i.e., 5) could be combined with a high consumption of bio-based distillate fuels scenario (i.e., 3). Such a scenario would serve to illustrate the benefits of distributing biofuels consumption between the motor gasoline and DFO sectors in order to alleviate some of the implications associated with a rapid penetration of ethanol in a motor gasoline sector with reduced overall demand. However, assessing the implications of minor permutations from this set of scenarios should not dictate the need to conduct an ever increasing number of model runs. The scenarios presented in this section, although limited, illustrate a wide range of characteristics of, and barriers to, a biofuels transition in the liquid fuels sector.

4.4.1 Scenario 1: RFS compliance base case

As mentioned above, scenario 1 serves as a base case. Total liquid fuels demand is derived from the AEO 2009 *stimulus* case (i.e., AEO case is set to 1, the *stimulus* case). The biofuel demand function is based on annual biofuel volumes from the EPA control case presented in Table 4-3. The ethanol blend limit is set to 10%, the current limit imposed by the CAA. This base case scenario is nearly analogous to the *stimulus* case projection. However, while the *stimulus* case projection shows a shortfall in biofuels consumption, this scenario meets the annual volume requirements of the RFS through 2022.

The EPA control case results in a transition scenario that is primarily based on increasing ethanol consumption in the motor gasoline sector—an “ethanol-centric” scenario. Conventional, corn-based ethanol is capped at 15 bgy in 2015. Cellulosic ethanol production expands to satisfy the annual cellulosic biofuel mandate, and ethanol imports from Brazil satisfy a majority of the other advanced biofuels category. Consumption of bio-based distillates grows slowly, as markets for oil-based feedstocks (e.g., vegetable oils, rendered animal fats, recycled cooking grease, etc) are expected to remain tight in the foreseeable future, according to the EPA [25].

Figures 4-8 through 4-10 show the model results for scenario 1 from 2006 through 2022.

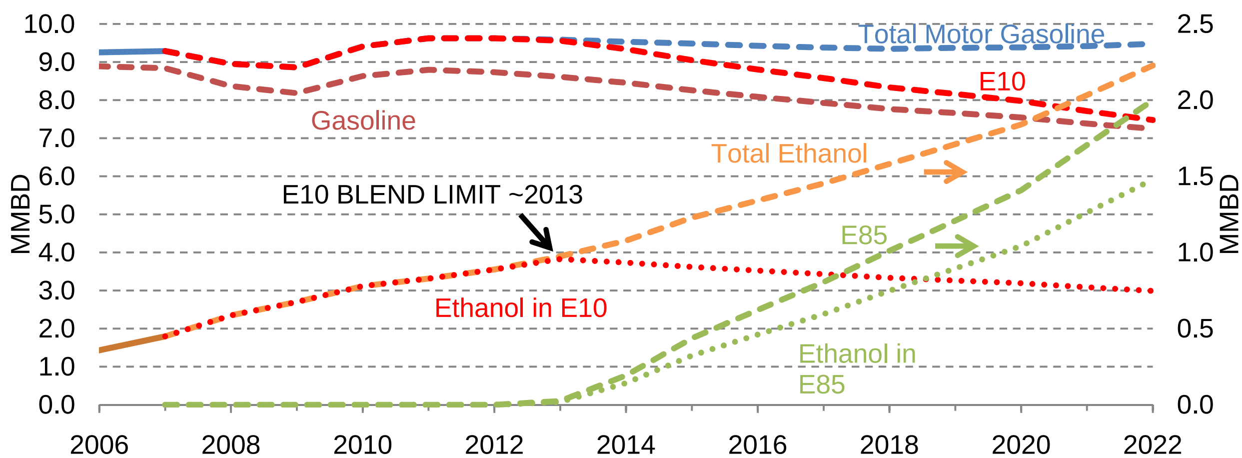


Figure 4-8. The base case scenario results in rapid penetration of ethanol in the motor gasoline sector. Crude-based gasoline consumption falls to 7.2 MMBD in 2022. The upper data sets (Total Motor Gasoline, E10, and Gasoline) are read from the left axis of the chart; the remaining data sets are read from the right.

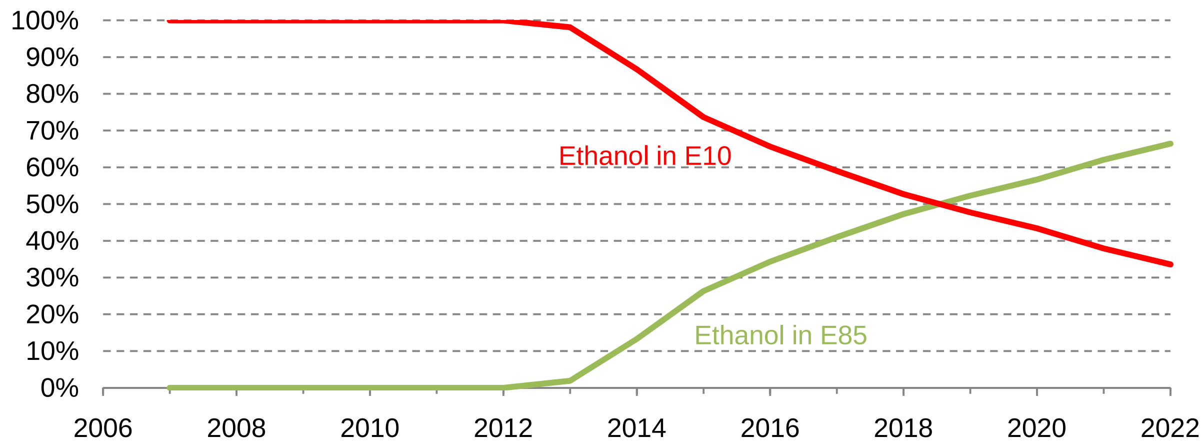


Figure 4-9. The rapid penetration of ethanol requires a transition in ethanol consumption; ethanol is increasingly consumed as E85 due to a shrinking crude-based gasoline supply. The left axis is the percentage of the ethanol supply blended in motor gasoline or E85.

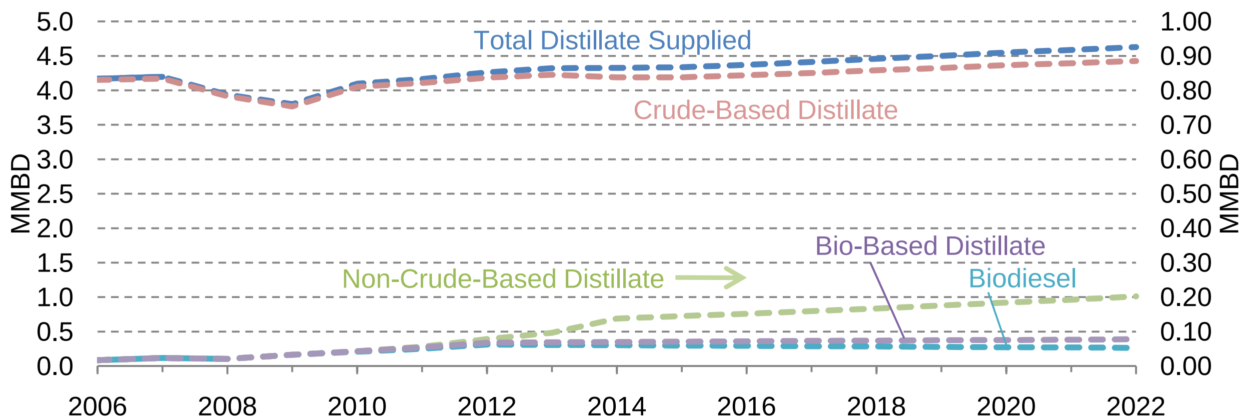


Figure 4-10. The base case scenario assumes a limited consumption of bio-based distillate, resulting in minimal displacement of crude-based distillate in the DFO sector. The upper data sets (Total Distillate Supplied and Crude-Based Distillate) are read from the left axis of the chart; the remaining data sets are read from the right. Recall that non-crude-based distillate includes bio-based distillate and CTL; bio-based distillate includes biodiesel and BTL/RD fuels.

Figure 4-8 illustrates the rapid penetration of ethanol into the motor gasoline sector. With flat demand for total motor gasoline, crude-based gasoline (i.e., Gasoline) consumption falls precipitously. Consumption falls from a recovered level of 8.80 MMBD in 2011 to 7.25 MMBD in 2022—a contraction of over 1.5 MMBD in just over 10 years. The 10% blend limit is reached in approximately 2013, requiring E85 to enter the market. As the crude-based gasoline supply shrinks and ethanol supply grows, ethanol must increasingly be blended as E85. By 2019, more ethanol is consumed as E85 than as motor gasoline (e.g., E10).

Recall that the model allocates all ethanol to motor gasoline blends (e.g., E10) on an annual basis until the blend limit is reached. In subsequent years, ethanol is allocated between motor gasoline blends and E85, keeping the motor gasoline blend level equal to the blend limit. This simplifying approach is based on the assumption that a negligible quantity of E85 enters the market prior to reaching the blend limit. This approach stands in contrast to analysis presented in the EPA RFS2 DRIA. EPA analysts assume that the E85 market expands prior to hitting the blend wall, such that an E85 infrastructure is being developed before the blend limit dictates the need for E85 in the motor gasoline sector [25]. As shown in Figure 4-5(d), EIA projections show negligible E85 penetration prior to 2013-2014, coinciding with the 10% blend limit. EIA analysts explain that penetration of E85 is delayed until more E85-compatible vehicles (i.e., FFVs) are in use and market infrastructure for E85 is expanded. The slow penetration of E85 hampers the overall growth in ethanol consumption, contributing to the shortfall projected by the EIA [173]. In this transition scenario, which meets the RFS mandate through rapid growth in ethanol consumption, the need for FFVs and E85 infrastructure is magnified.

Results for the DFO sector are shown in Figure 4-10. With constrained production of bio-based distillates in the EPA control case, biofuels supply less than 2% of total distillate demand (on a volume basis) in 2022, resulting in a minimal displacement of crude-based distillate.

4.4.2 Scenario 2: Increased ethanol blend limit

Scenario 2 examines the impacts of an increased ethanol blend limit. Since the blend limit variable only impacts results for the motor gasoline sector, results for the DFO sector are omitted.[51] All inputs and assumptions are analogous to scenario 1, expect for the blend limit variable, which is increased up to 20%. By altering the blend limit parameter while holding all other parameters constant, implications of the blend wall are revealed. Results for scenario 2 are presented in Figures 4-11 through 4-13.

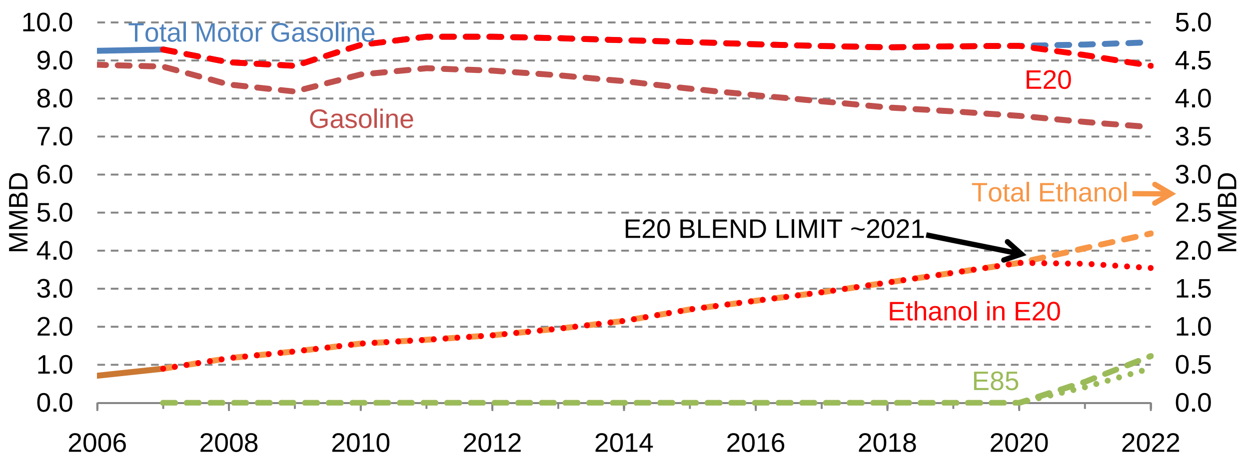


Figure 4-11. Increasing the blend limit from 10 to 20% (i.e., E20) delays the introduction of E85 by approximately 8 years. Note the change of scale on the right axis when compared to Figure 4-8. The upper data sets (Total Motor Gasoline, E10, and Gasoline) are read from the left axis of the chart; the remaining data sets are read from the right.

[51] For discussions on blend limits in the DFO sector, refer to sections 4.2.1.2 and 4.3.4.

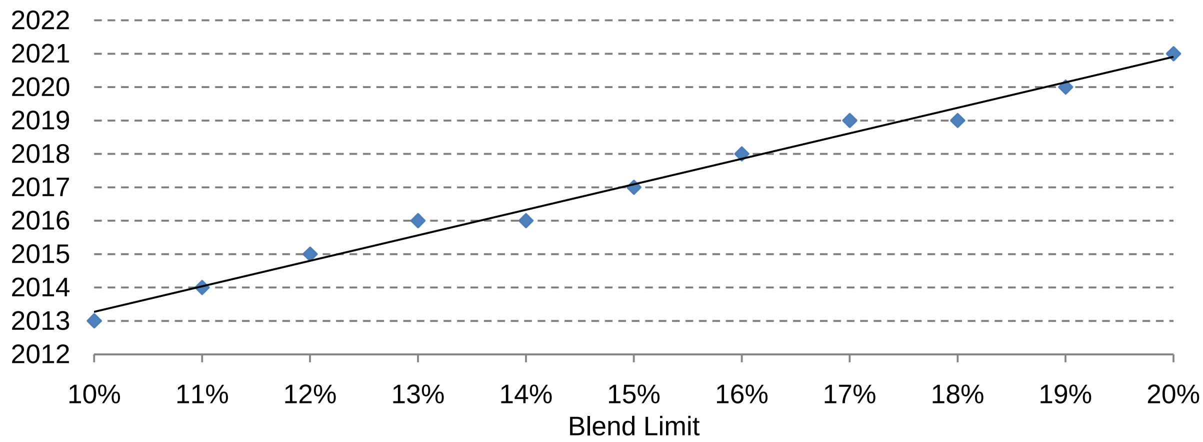


Figure 4-12. By increasing the blend limit variable from 10% to 20%, a relationship between the blend limit year and percentage is revealed. The left axis is the year when the blend limit is reached for a given blend limit percentage.

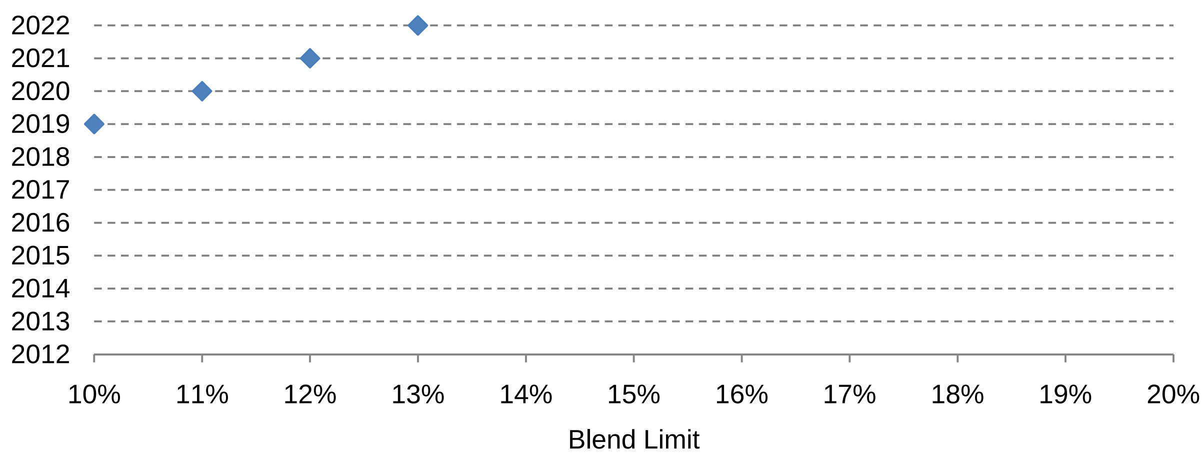


Figure 4-13. This figure shows the year at which ethanol consumption in E85 first exceeds ethanol consumption in motor gasoline for a given blend limit percentage. For example, a blend limit of 10% requires more ethanol to be consumed as E85 starting in 2019. When the blend limit exceeds 13%, the amount of ethanol blended as E85 never exceeds the amount blended in motor gasoline through 2022.

Recall that the data series labeled as 'E20' and 'Ethanol in E20' in Figure 4-11 do not represent volumes of E20 throughout the entire time series. Once the 20% blend limit is reach in 2021, the data do in fact represent a motor gasoline pool that is, on average, at a 20% blend. Prior to reaching the limit, the average blend level is less than 20%. Since this scenario is based directly on scenario 1, the average blend level in 2013 is 10%, the year the 10% blend limit is reached in scenario 1.

The impact of increasing the blend limit is shown in Figure 4-11. The 20% blend limit is reached around 2021, 8 years later than the 10% limit. With an increased blend limit, the need to develop an E85 market is delayed, and the amount of ethanol needed to be consumed as E85 is drastically reduced. In 2022, the 10% limit requires 1.5 MMBD of ethanol to be consumed as E85 (66% of total ethanol), while the 20% limit requires only 0.5 MMBD (20% of total ethanol).

Figure 4-12 was developed by incrementing the blend limit variable from 10% to 20% in 1% increments and determining the year when the given blend limit is reached. Between the 10% and 20% limits, the relationship is essentially linear—the 15% limit is reached in 2017, the midpoint between the 10% and 20% limits. Figure 4-13, which also plots the blend limit percent on the horizontal axis, shows the year when ethanol consumption in E85 first exceeds that in motor gasoline. At a 10% blend limit, this occurs in 2019. If the limit is increased above 13%, a greater volume of ethanol is consumed in motor gasoline blends through 2022, i.e., the E85 market requires a smaller share of the total ethanol supply through 2022.

Currently, the CAA sets a 10% limit on ethanol in motor gasoline blends. In the CAA, the "substantially similar" rule limits oxygen content in motor gasoline fuels to 2.7% by weight [174]:

> The allowable oxygen content for a "substantially similar" unleaded gasoline is…2.7 percent by weight, for blends of aliphatic alcohols and/or ethers, excluding methanol.

This oxygen limit equates to an ethanol-in-gasoline blend of 7.0% to 7.5%. A 10% blend results in an oxygen content of 3.7%, which exceeds the "substantially similar" rule by 1%. Ethanol blends are allowed to exceed the oxygen limit due to an approved waiver request under section 211(f) of the CAA [160]. In order to increase the limit beyond 10%, an amendment to the CAA or another waiver request must be approved. Growth Energy and 54 ethanol manufacturers submitted such a request on March 6, 2009, seeking a waiver for blends up to 15% (i.e., E15). The Administrator of the EPA must grant or deny this request by December 1, 2009 [25, 175].[52]

In the RFS2 DRIA, the analysis is primarily centered on an E10/E85 future. In addition, EPA analysts investigated the possibility of a waiver request to increase the blend limit. E15 and E20 blend limits were investigated. This analysis does not simply shift from an E10/E85 market to an E15/E85 or E20/E85 market. Instead, the EPA acknowledges that there may be a need to continue to supply E10 for legacy vehicles. Vehicle manufacturers warrant non-FFV vehicles to run on blends no greater than E10. Therefore, unless manufacturers grant approval for legacy vehicles to operate on blends greater than E10, the market must continue to have a sufficient supply of E10. The EPA assumes that such an approval would not be granted for the legacy fleet. Therefore, in their analysis, the motor gasoline supply consists of E10 for legacy vehicles, E15/E20 for Tier 2 or FFVs, and E85 exclusively for FFVs. Despite this complication, the average blend level of motor gasoline (not including E85) still increases. With a blend limit of 15-20%, the average blend level of motor gasoline would stand between 10% and 15-20%. Although a portion of the motor gasoline market might still need to be supplied with E10, by allowing greater penetration of mid-level blends (e.g., E15), the size of the E85 market is reduced. In the simple scenario presented above, the blend limit could represent the average blend level of motor gasoline, which could be made up of blends ranging from 0-20%. Implications of altering the blend are discussed further in section 4.5.

---

[52] On November 30, 2009, the EPA notified Growth Energy that the waiver request decision would be delayed until mid-year 2010, pending results from DOE vehicle test programs. The letter can be viewed here: http://www.growthenergy.org/static/docs/2009/11/letter_EPAtoGrowthEnergy.pdf

4.4.3 Scenario 3: Increased consumption of bio-based distillate

Scenario 3 investigates the impacts of shifting biofuels consumption away from the motor gasoline sector by increasing bio-based distillate consumption. All inputs and assumptions are analogous to scenario 1, expect for the biofuel demand function. Two model runs were conducted as part of this scenario, presented below as scenarios 3(a) and 3(b). These scenarios depart from the "ethanol-centric" futures that are based on the biofuel assumptions of the EPA control case.

4.4.3.1 Scenario 3(a)

In this scenario, the cellulosic biofuel mandate is split evenly between cellulosic ethanol and cellulosic diesel (i.e., BTL) annually. For example, in 2015, the 3 bgy mandate is met with 1.5 bgy of ethanol and 1.5 bgy of BTL. In addition, the volumes of imported ethanol in the EPA control case are shifted entirely to the production of bio-based distillate (e.g., renewable diesel and/or BTL). Results are presented in Figures 4-14 through 4-17.

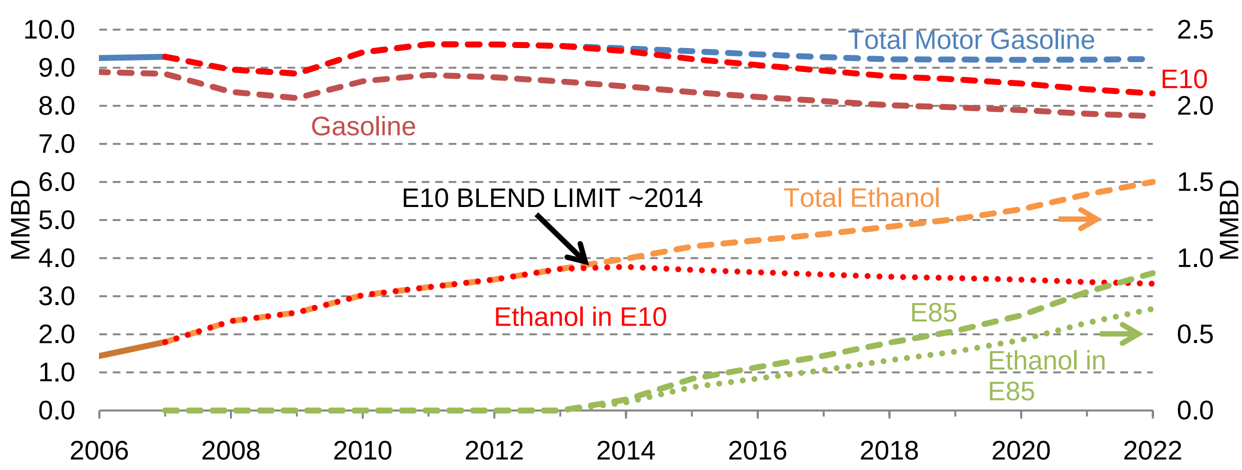


Figure 4-14. Total ethanol consumption is reduced due to the altered biofuel assumptions; only one half of the cellulosic biofuel requirement is met with ethanol. By diverting this biofuel consumption from the motor gasoline to the DFO sector, the blend limit is delayed by 1 year, the growth of the E85 market is reduced, and ethanol consumption in motor gasoline is greater than in E85 through 2022 (see Figure 4-16).

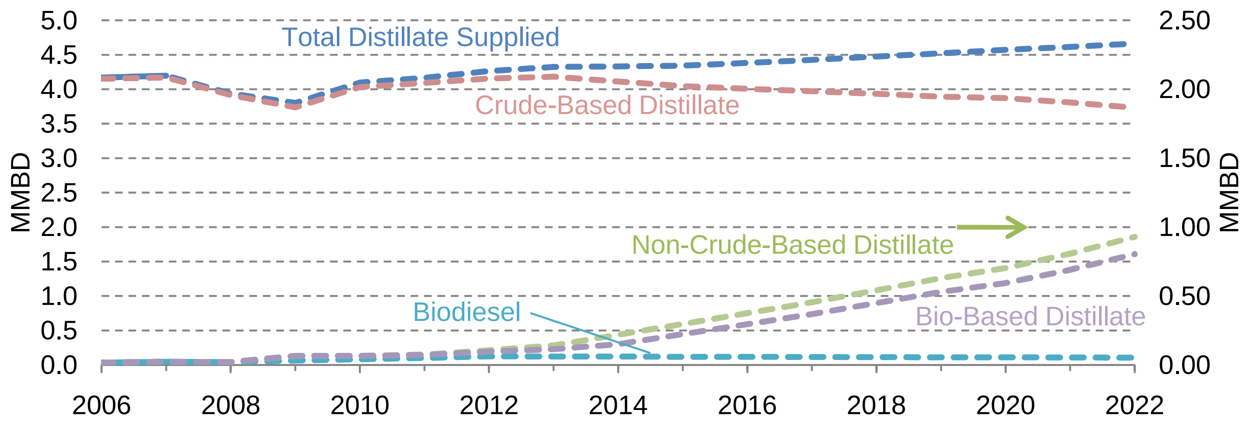


Figure 4-15. Scenario 3 assumes that one half of cellulosic biofuel consumption is met with cellulosic diesel (i.e., BTL). The increased supply of bio-based distillate results in a decrease in crude-based distillate demand after 2013, mimicking the "peak gasoline" phenomenon in the motor gasoline sector. Note the change of scale on the right axis when compared to Figure 4-10.

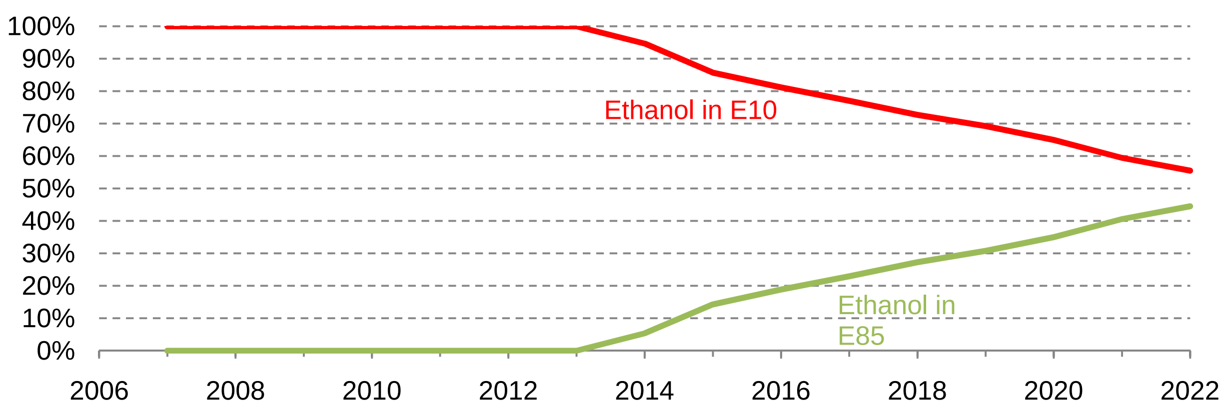


Figure 4-16. Ethanol consumption in motor gasoline (i.e., E10) is greater than in E85 through 2022 due to the reduced market penetration of cellulosic ethanol (and total ethanol). The left axis is the percentage of the ethanol supply blended in motor gasoline or E85.

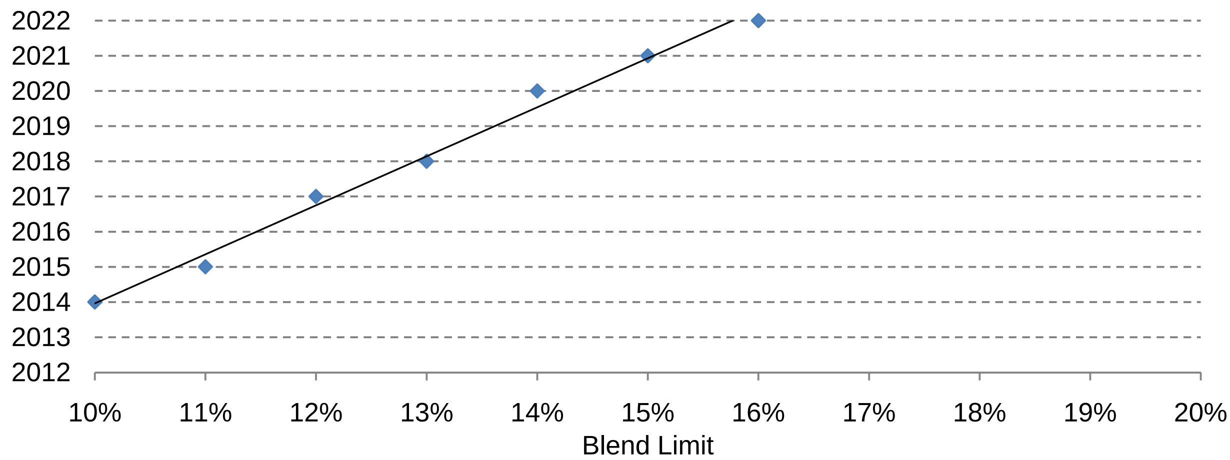


Figure 4-17. When compared to Figure 4-12, which is based on the base case scenario, the blend limit trend is shifted up and has a greater slope, i.e., the decrease in total ethanol consumption delays the blend limit year for a given blend limit percentage. If the blend limit is greater than or equal to 16%, no E85 market is needed through 2022.

Total ethanol consumption in 2022 is reduced by 0.5 MMBD to 1.5 MMBD when compared to scenario 1; with less total ethanol consumption, crude-based gasoline consumption does not decline as rapidly. The E10 blend limit is delayed by only 1 year to 2014. However, with slower growth in total ethanol consumption, the E85 market develops slowly, and the majority of the ethanol supply is consumed as motor gasoline (i.e., E10) through 2022 (see Figure 4-16). Figure 4-17 shows the results of increasing the blend limit above 10%. Like Figure 4-12, increasing the blend limit delays the year when the blend limit is reached. But, in this case, since total ethanol consumption grows more slowly than in scenario 2, a given increase in the blend limit percentage delays the blend limit year more rapidly. For example, when the blend limit is increased from 10% to 15% in this scenario, the blend limit year is delayed by 7 years (2014 to 2021). As shown in Figure 4-12, this same increase in the blend limit for scenario 2 causes a delay of only 4 years (2013 to 2017). For a blend limit greater than or equal to 16%, no E85 market is needed through 2022.

Results for the DFO sector are shown in Figure 4-15. In 2022, consumption of bio-based distillate is increased by more than 0.7 MMBD when compared to scenario 1. The growth in bio-based distillate consumption causes demand for crude-based distillate to subside after a peak in 2013. From 2013 to 2022, consumption of crude-based distillate is reduced by 0.3 MMBD. This drop in crude-based distillate mimics the "peak gasoline" phenomenon in the motor gasoline sector. In addition, for each gallon of ethanol replaced by bio-based distillates, a greater amount of the total liquid fuels energy demand is met, thereby reducing the total volume of liquid fuels consumption.[53] In 2022, this scenario results in a total liquid fuels volume of 13.89 MMBD compared to 14.10 MMBD for scenarios 1 and 2—a reduction of 212 MBD.

4.4.3.2 Scenario 3(b)

Scenario 3(b) is analogous to 3(a) in all regards except that the annual volume mandate for cellulosic biofuel is met entirely with cellulosic diesel (i.e., BTL). For example, in 2015, the 3 bgy mandate is met with 3 bgy of BTL. Results are presented in Figures 4-18 and 4-19.

[53] Recall that the liquid fuels transition model is designed to satisfy the energy demanded by the motor gasoline and DFO sectors, not the volume, since different fuels have different energy contents.

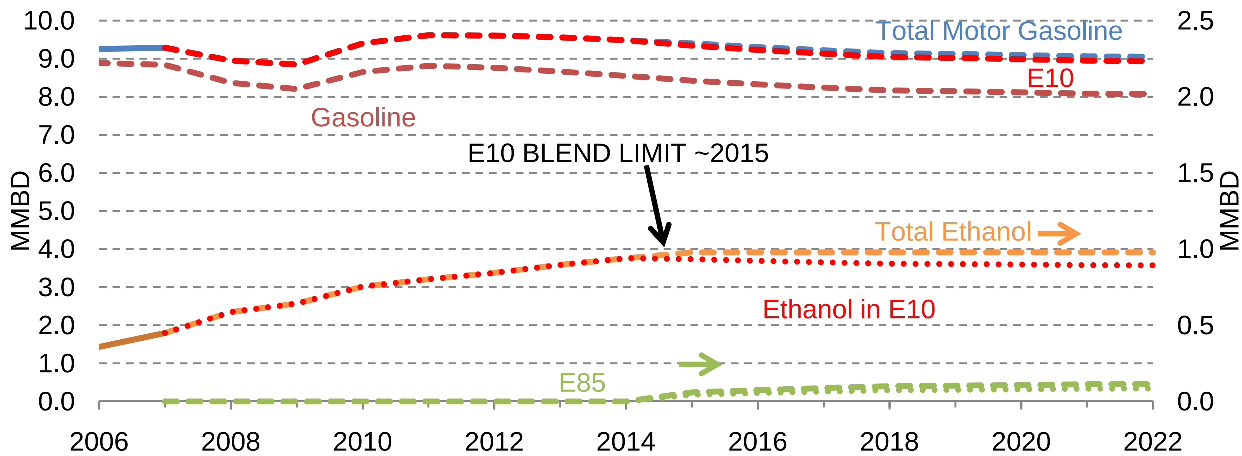


Figure 4-18. Total ethanol consumption plateaus in 2015 when the non-advanced biofuel, or conventional biofuel, category is capped at 15 bgy (~1 MMBD). With the entire cellulosic biofuel mandate shifted to the DFO sector, the ethanol supply does not grow beyond 2015.

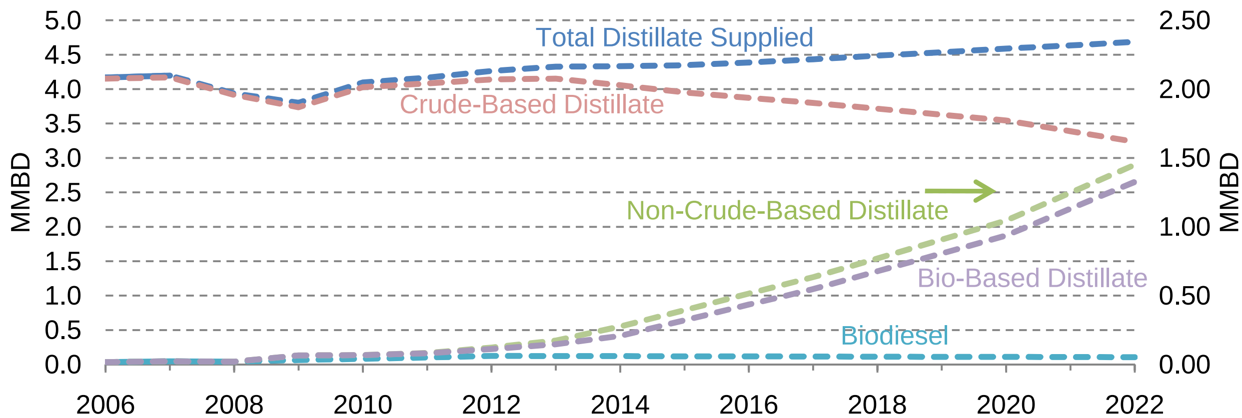


Figure 4-19. The bio-based distillate supply grows rapidly as cellulosic diesel is produced to meet the cellulosic biofuel mandate. Crude-base distillate consumption drops rapidly after 2013 and is 0.5 MMBD less in 2022 when compared to scenario 3(a). From 2013 to 2022, crude-based distillate consumption contracts by nearly 1 MMBD.

Results for scenario 3(b) exhibit the same trends as 3(a), except that these trends are magnified. Since the entire cellulosic biofuel mandate is met with BTL, total ethanol consumption stops growing after the conventional biofuel category is capped at 15 bgy (~1 MMBD) in 2015. Since total motor gasoline demand is nearly constant after 2015, consumption trends exhibit negligible change through 2022.

Unlike scenario 3(a), there is no blend limit chart (e.g., Figure 4-17) shown for scenario 3(b). If this chart is produced for scenario 3(b), only one data point would be shown—the 10% limit in 2015. Since the ethanol supply does not expand beyond 2015, an 11% limit is never reached in this scenario. By increasing the blend limit to 11%, an E85 market becomes unnecessary since all ethanol is able to be blended as motor gasoline (up to E11).

Rapid growth in bio-based distillate consumption results in a precipitous drop in crude-based distillate consumption after 2013, falling by nearly 1 MMBD from 2013 to 2022. With even more ethanol replaced by the higher energy containing bio-based distillate (i.e., BTL), total liquid fuels volume falls to 13.74 MMBD—a reduction of 364 MBD when compared to the "ethanol-centric" scenarios (1 and 2). This reduction in total liquid fuels volume results not only from the replacement of ethanol with bio-based distillate, but also from the need for crude-based gasoline to supply the energy demand in the motor gasoline sector that is no longer supplied by ethanol. This issue is illustrated by the slight reduction in total motor gasoline consumption (e.g., in 2022) when comparing scenarios 3(a) and (b), i.e., Figures 4-14 and 4-18.

4.4.4 Scenario 4: Increased consumption of non-ethanol bio-based gasoline

Scenario 4 is similar to scenario 3(b), except that the cellulosic ethanol is replaced by other bio-based gasoline substitutes, like renewable gasoline or biobutanol, rather than bio-based distillate. Only one model run was executed, with renewable gasoline replacing cellulosic ethanol in the biofuel demand function. A biobutanol scenario was not run through the model. However, biobutanol as a gasoline substitute is discussed briefly in section 4.4.4.2. First, the renewable gasoline scenario is presented.

4.4.4.1 Renewable gasoline

When compared to the base case scenario, only the biofuel demand function is altered. The cellulosic biofuel mandate is met entirely with renewable gasoline rather than cellulosic ethanol. This change is based on the assumption that renewable gasoline, a bio-derived synthetic gasoline, is produced from cellulosic feedstocks and meets the lifecycle GHG emissions reduction target for cellulosic biofuel (60%). Since renewable gasoline is chemically identical to crude-based gasoline, the blend limit and infrastructure compatibility issues that face ethanol do no apply. The 10% blend limit still applies to the remaining ethanol supply, and total demand is still based on the AEO 2009 *stimulus* case.

Minor changes to the model calculations for the motor gasoline component were needed to execute the model run for this scenario. Renewable gasoline was not incorporated into the motor gasoline calculations in the base model (see section 4.3.4). With energy content nearly identical to crude-based gasoline,[54] renewable gasoline is treated as an additional supply of crude-based gasoline. In the ethanol blend calculations, renewable gasoline and crude-based gasoline volumes are combined for blending with ethanol. However, since renewable gasoline is a biofuel, it still acts to reduce crude-based gasoline consumption.

Results for the motor gasoline sector are presented in Figures 4-20 and 4-21. DFO results are identical to scenario 1 since the inputs impact only the motor gasoline results; see Figure 4-10.

---

[54] Referring to Table 4-4, the LHVs of renewable gasoline and crude-based gasoline are 115,983 and 115,261 Btu/gallon, respectively.

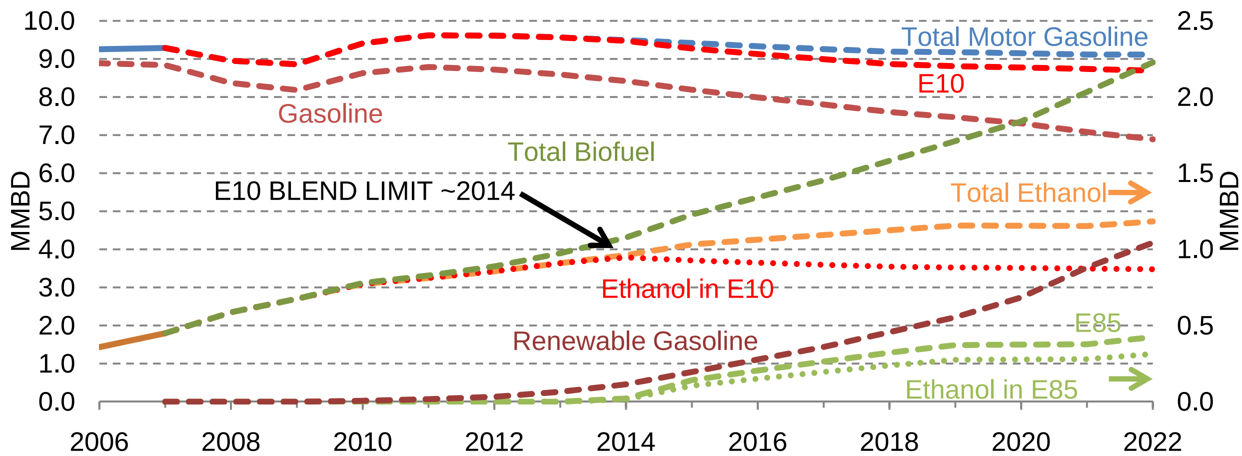


Figure 4-20. The renewable gasoline industry replaces the cellulosic ethanol industry in this scenario. The E10 blend limit is delayed by one year relative to the base case (i.e., scenario 1). However, with the slow growth in ethanol consumption after 2015, market penetration of E85 is reduced. The upper data sets (Total Motor Gasoline, E10, and Gasoline) are read from the left axis of the chart; the remaining data sets are read from the right.

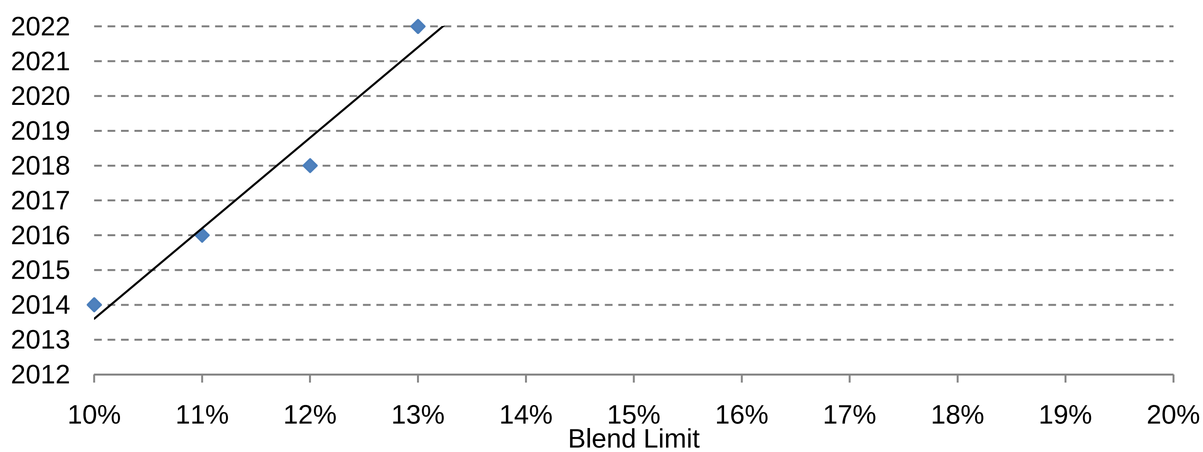


Figure 4-21. As biofuel consumption in the motor gasoline sector shifts from ethanol to renewable gasoline, the blend limit year is delayed for a given percentage when compared to the base case (see Figure 4-12). If the blend limit is greater than or equal to 13%, no E85 market is needed through 2022.

Figure 4-20 shows two additional data series when compared to other motor gasoline sector charts (e.g., Figure 4-8): 'Total Biofuel' and 'Renewable Gasoline'. The total biofuel volume is determined by summing the annual volumes of renewable gasoline and total ethanol.

By substituting cellulosic ethanol with renewable gasoline, several changes occur. First, although the blend limit is delayed by only 1 year when compared to scenario 1, the slower growth in ethanol consumption in subsequent years results in a slow penetration of E85. With a smaller E85 market, more ethanol is consumed as motor gasoline (i.e., E10) through 2022. Second, increasing the blend limit delays the blend limit year very rapidly. As shown in Figure 4-21, an increase in the blend limit from 10% to 13% causes a delay of 8 years (2014-2022). Compared to scenario 2 (Figure 4-12), this same increase in the blend limit saves only 3 years (2013-2016). Again, when the blend limit year is delayed, the market entry of E85 is similarly delayed (and the size of the E85 market is limited). Third, due to the gallon-for-gallon replacement of ethanol with renewable gasoline, a greater reduction in crude-based gasoline consumption results when compared to scenario 1. Crude-based gasoline consumption falls to 6.89 MMBD in 2022, compared to 7.25 MMBD in the base case.

4.4.4.2 Biobutanol

Biobutanol has been touted as a gasoline substitute with more advantageous properties than ethanol. Biobutanol is the term given to butanol (i.e., C_4H_9OH) that is derived from biomass an intended for use as a fuel. The energy content of butanol is 99,837 Btu/gal (LHV) [167]. Butanol's energy content is over 30% greater than that of ethanol (76,330 Btu/gal). Butanol also has a slightly higher density than ethanol. Integrating butanol blends into the motor gasoline sector could alleviate some of the challenges posed by ethanol (e.g., phase-separation in the presence of water). Advocates of butanol explain that the alcohol could be blended at higher percentages than ethanol before encountering material compatibility issues in vehicles and the distribution and retail infrastructure [176].

However, the "substantially similar" rule of the CAA currently limits butanol content in gasoline to 11.5% by volume [174]. Recall from section 4.4.2 that the "substantially similar" rule limits oxygen content in unleaded gasoline to 2.7% by weight. Unlike ethanol, butanol has not been granted a waiver [160]. The ethanol waiver allows for 10% blends of ethanol by volume, which equates to an oxygen content of 3.7% by weight. If a butanol waiver was approved, allowing butanol to be blended with gasoline to a maximum oxygen content of 3.7% by weight, then butanol blends up to 16% would be permitted. The following equation is used determine the oxygen content of alcohol-gasoline blends:

$$\% \text{ O by wt.} = \frac{\left(\frac{\text{blend }\%}{100} * \rho_{\text{alcohol}} * \frac{16\text{ g}}{\text{MW}_{\text{alcohol}}}\right)}{\left(\frac{\text{blend }\%}{100} * \rho_{\text{alcohol}}\right) + \left(\left(1 - \frac{\text{blend }\%}{100}\right) * \rho_{\text{gasoline}}\right)}$$

$$3.7\% \text{ O by wt.} = \frac{\left(0.16 * 3065\frac{\text{g}}{\text{gal}} * \frac{16\text{ g}}{74\text{ g}}\right)}{\left(0.16 * 3065\frac{\text{g}}{\text{gal}}\right) + \left((1-0.16) * 2819\text{ g/gal}\right)}$$

Without an approved waiver request under section 211(f) of the CAA, butanol would likely do little to alter a biofuel transition in the motor gasoline sector. Compared to the 10% limit imposed on ethanol, the dynamics of a transition would be only slightly altered with an 11.5% limit imposed on butanol. With an approved waiver request, substituting ethanol with butanol on a gallon-for-gallon basis would delay the blend limit (from 10% to 16%) and limit the need for a high-blend market. Greater reductions in crude-based and total motor gasoline consumption would result from the increase in energy content when ethanol is replaced with butanol. However, since an ethanol industry is already established, the wholesale replacement of ethanol with butanol, at least in the near term, is improbable. If a butanol industry develops to supply the motor gasoline sector, questions could arise as to whether ethanol-gasoline blends could co-mingle with butanol-gasoline blends. In addition, the advantages of utilizing butanol as a fuel could be outweighed by the challenges of incorporating a second alcohol fuel into the motor gasoline supply.

In 2006, DuPont and BP publicly announced their plans to develop biobutanol for the commercial market. The two companies have been working jointly since 2003 to develop the fuel, and had planned to introduce the first commercial volumes of biobutanol in Europe in 2007 [177]. However, these plans appear to have been delayed, with a subsequent announcement explaining that "market development" quantities of biobutanol were to be introduced in the UK in early 2009 [178]. A more recent announcement explains that BP is planning to produce commercial quantities of biobutanol from a facility in the UK by 2012/2013 [179].

4.4.5 Scenario 5: Variable liquid fuels demand

Total liquid fuels demand is based on the AEO 2009 *stimulus* case in scenarios 1-4. For this final set of scenarios, the impact of increasing/decreasing total liquid fuels demand is investigated. As discussed at the end of section 4.2, the *lp* and *hp* cases are used to alter the total liquid fuels demand function. The biofuel demand function is identical to the base case (i.e., scenario 1), and the blend limit is initially set to 10%. The effect of altering the blend limit is also assessed. Two model runs were executed, and are presented below as scenarios 5(a) and (b). The scenarios differ only in their specification of the AEO 2009 case: scenario 5(a) uses the *hp* case; scenario 5(b) uses the *lp* case.

Several factors could impact total liquid fuels demand in the coming decade:

- Deepened economic recession;
- Economic recovery and sustained growth;
- Increased electrification of the LDV fleet (e.g., HEV, PHEV, EV);
- Dieselization;
- Increased fuel efficiency standards (e.g., CAFE);
- Altered consumer behavior (e.g., reduction in VMT, increased use of mass transit);

- FFV production (and sales) rates.

Assessing the probability of occurrence and quantitative impacts of such factors in the liquid fuels sector would be a massive undertaking. Rather than undertaking such a rigorous, and potentially failed, exercise, the simple scenarios presented below help to illustrate the general impacts that changes in total liquid fuels demand could have on a biofuels transition. Although the AEO 2009 *hp* and *lp* cases are based on altered assumptions related to future world oil prices, any number of the factors listed above could influence liquid fuels demand in qualitatively similar ways. In addition, the overarching design of the RFS mandate can be assessed by altering the total liquid fuels demand function. As a volume-based mandate, the RFS program requires an annually increasing volume of biofuels to be consumed, regardless of changes in total demand. This design influences how a biofuels transition will unfold in the next decade.

4.4.5.1 Scenario 5(a): Decreased liquid fuels demand

Scenario 5(a) derives total liquid fuels demand from the AEO 2009 *hp* case, bases the biofuel demand function on EPA control case volumes, and initially applies a 10% blend limit in the motor gasoline sector. Results are presented in Figures 4-22 through 4-26.

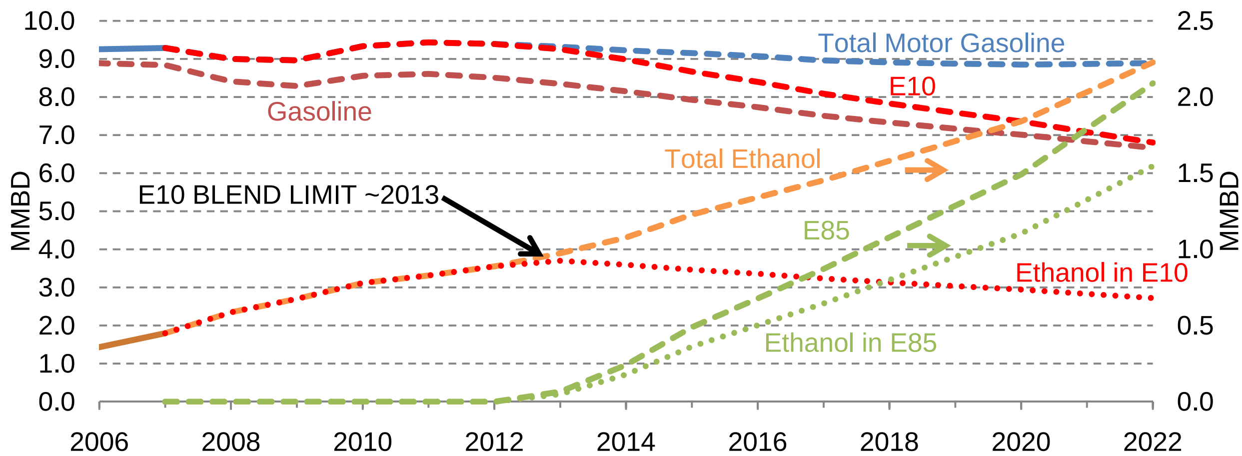


Figure 4-22. The AEO2009 *hp* case results in decreased total motor gasoline demand. Crude-based gasoline consumption falls rapidly compared to the base case (i.e., scenario 1). The upper data sets (Total Motor Gasoline, E10, and Gasoline) are read from the left axis of the chart; the remaining data sets are read from the right.

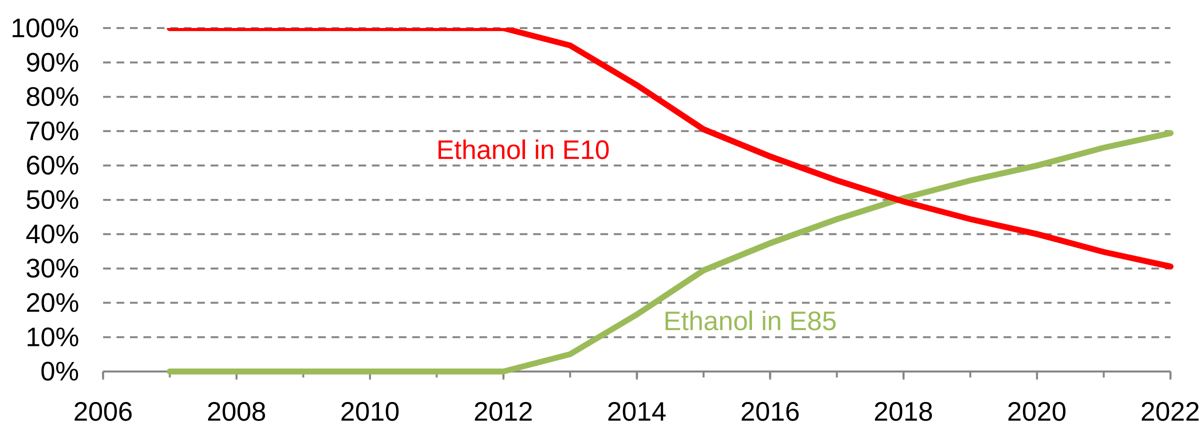


Figure 4-23. By 2018, more ethanol is consumed in E85 than in motor gasoline blends (e.g., E10). In 2022, ~70% of the ethanol supply is blended as E85. The left axis is the percentage of the ethanol supply blended in motor gasoline or E85.

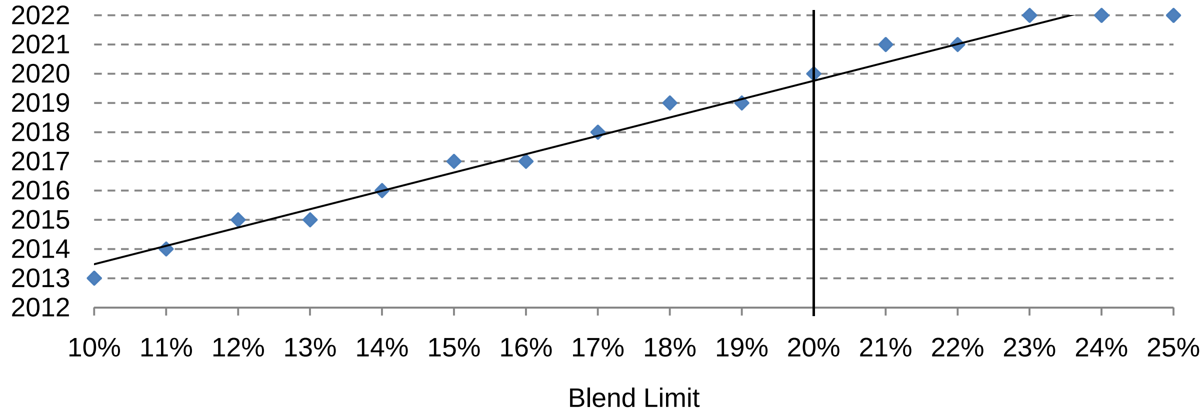


Figure 4-24. When compared to Figure 4-12, the blend limit year advances less for a given increase in the blend limit percentage. The blend limit must be increased beyond 25% to eliminate the need for an E85 market through 2022. The left axis is the year when the blend limit is reached for a given blend limit percentage.

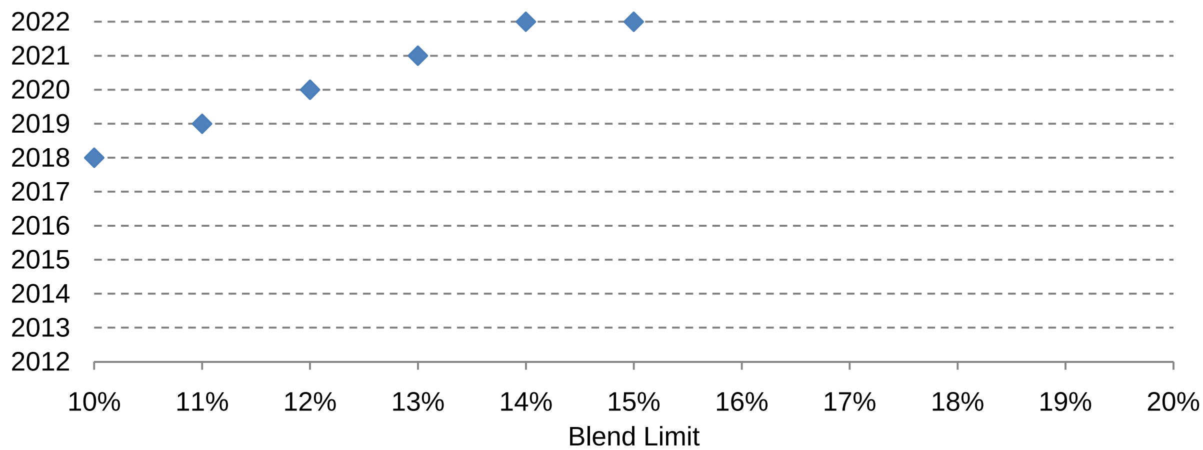


Figure 4-25. This figure shows the year at which ethanol consumption in E85 first exceeds ethanol consumption in motor gasoline (e.g., E10) for a given blend limit percentage (e.g., 10%).

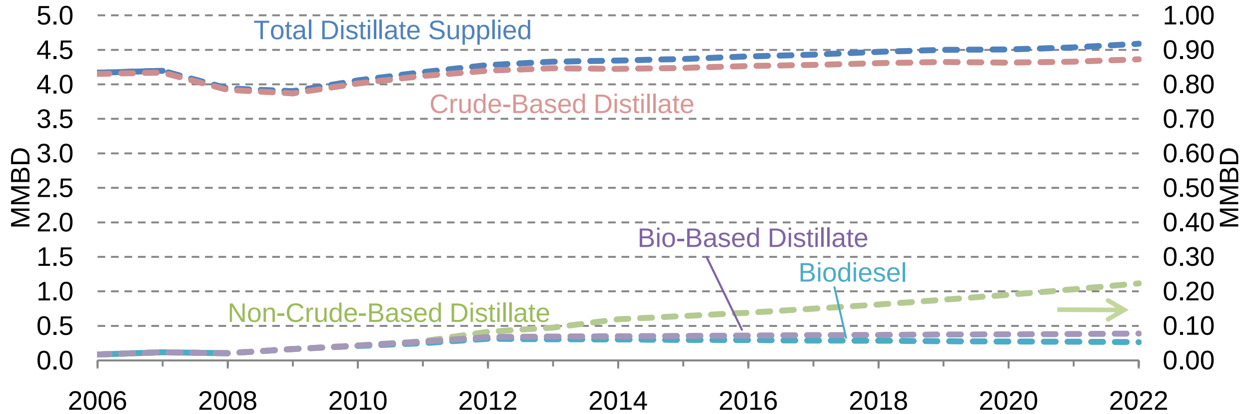


Figure 4-26. The AEO2009 *hp* case has little impact on total distillate demand. Since the EPA control case is used for biofuel demand assumptions, the DFO sector sees little penetration of biofuels, like scenario 1.

As shown in Figure 4-22, total motor gasoline demand falls below 9 MMBD in 2017. In scenario 1 (Figure 4-8), demand stays well above 9 MMBD, increasing to approximately 9.5 MMBD in 2020. The impacts of this reduced demand are immediately evident. As total ethanol consumption rises to satisfy the RFS, crude-based gasoline consumption falls rapidly, falling below 7 MMBD after 2020. By 2022, over 2 MMBD of crude-based gasoline demand is eliminated from its peak of nearly 9 MMBD. The 10% blend limit is still reached in 2013, but with falling total demand and increasing total ethanol consumption, the E85 market expands rapidly, requiring more ethanol than the motor gasoline market (i.e., E10) after 2017. By 2022, 70% of the ethanol supply is blended as E85 (see Figure 4-23). In 2022, ethanol supplies one-quarter of the volume in the motor gasoline sector.

By comparing Figure 4-24 to 4-12, the impact of increasing the blend limit is shown to differ little from the base case scenario. The 20% blend limit is reached in 2020, compared to 2021 in scenario 2. The blend limit must be increased beyond 25% to eliminate the need for an E85 market through 2022. The base case reaches this point when the blend limit is increased above 23%. Figure 4-25 shows that when the blend limit exceeds 15%, the amount of ethanol consumed as E85 never exceeds the consumption of ethanol in motor gasoline (e.g., E16) through 2022.

The AEO 2009 *hp* case has minimal impacts on total distillate demand. Since the biofuel demand function is again based on the EPA control case, there is little penetration of bio-based distillate. The impacts of a reduced distillate demand can be assessed by imagining the AEO 2009 *lm* case being combined with the biofuel demand function from either scenario 3(a) or (b). With growing consumption of bio-based distillate, and falling total distillate demand, crude-based distillate consumption would fall rapidly.

4.4.5.2 Scenario 5(b): Increased liquid fuels demand

Scenario 5(b) uses the AEO 2009 *lp* case for total liquid fuels demand, bases the biofuel demand function on EPA control case volumes, and initially applies a 10% blend limit in the motor gasoline sector. Results are presented in Figures 4-27 through 4-31.

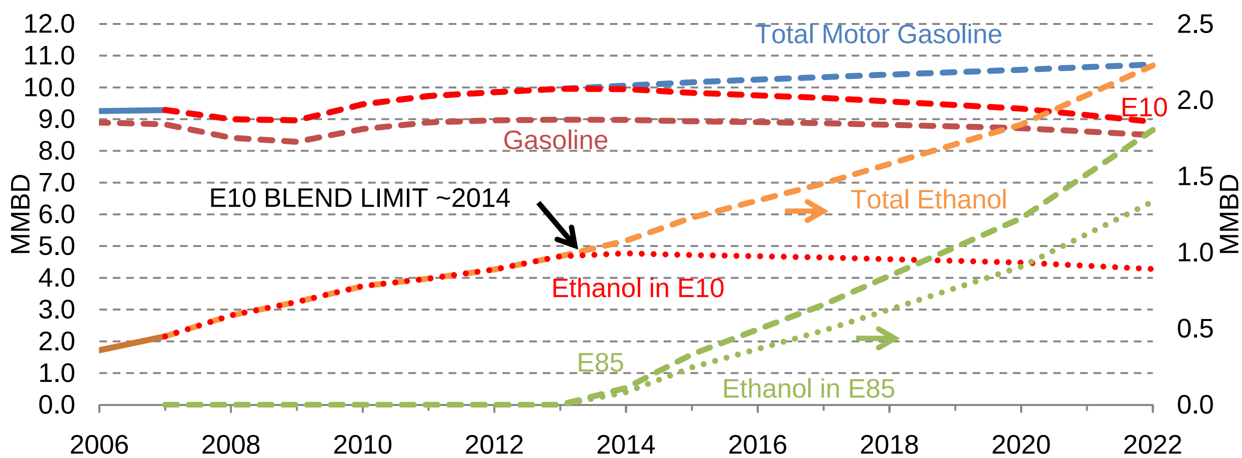


Figure 4-27. The AEO2009 *lp* case results in increased total motor gasoline demand. The 10% blend limit is delayed by one year, when compared to the *stimulus* and *hp* cases (i.e., scenarios 1 and 5a, respectively). Crude-based gasoline consumption remains nearly flat through 2022. Note the change of scale in the left axis when compared to Figure 4-8, or any other motor gasoline figure in this section. The upper data sets (Total Motor Gasoline, E10, and Gasoline) are read from the left axis of the chart; the remaining data sets are read from the right.

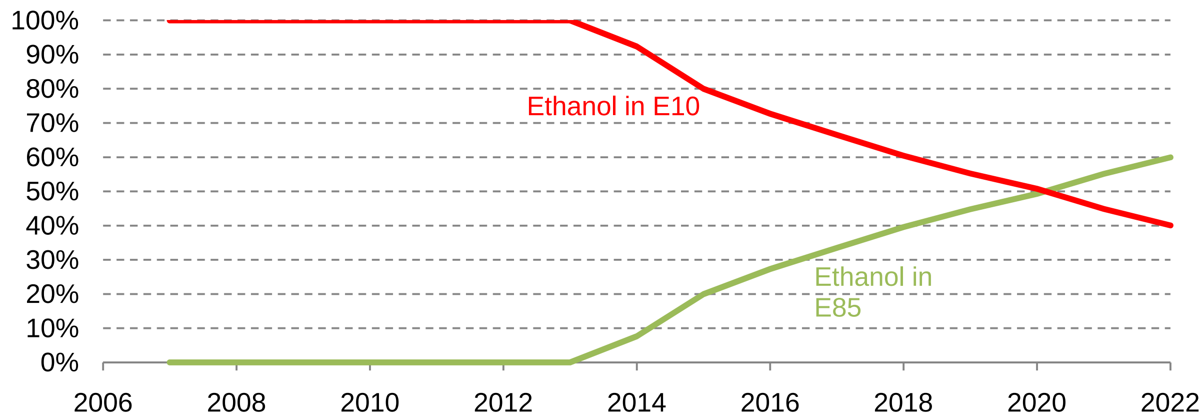


Figure 4-28. The growth in total motor gasoline demand delays the penetration of E85. More ethanol is consumed as E85 starting in 2020. In scenario 1, this transition occurs in 2019. The left axis is the percentage of the ethanol supply blended in motor gasoline or E85.

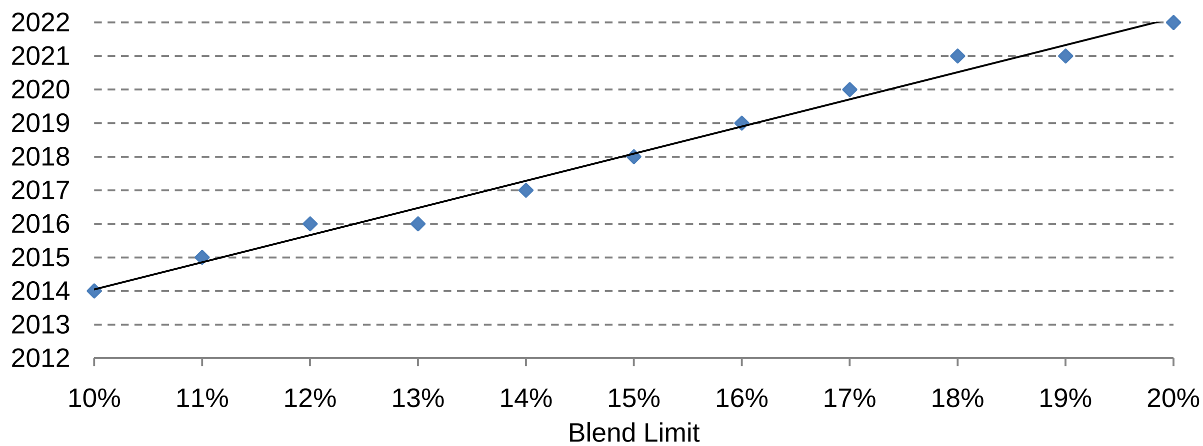


Figure 4-29. When compared to Figure 4-12, the blend limit year is delayed for a given percentage. The increased total motor gasoline demand provides a large supply of crude-based gasoline for blending with ethanol, thereby delaying the blend limit year. In this scenario, no E85 market is needed for a blend limit exceeding 20%. The left axis is the year when the blend limit is reached for a given blend limit percentage.

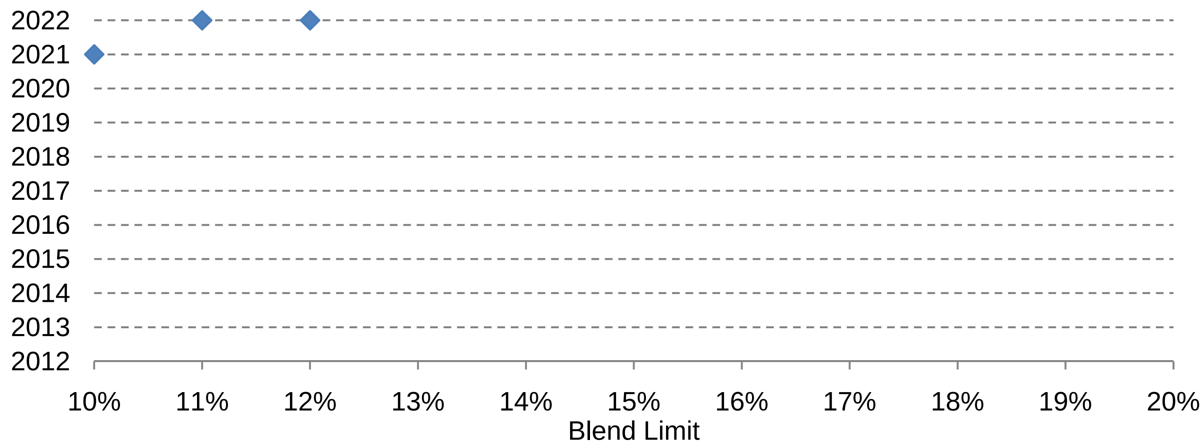


Figure 4-30. This figure shows the year at which ethanol consumption in E85 first exceeds ethanol consumption in motor gasoline for a given blend limit percentage (analogous to Figure 4-13). A blend limit of 10% requires more ethanol to be consumed as E85 starting in 2021. When the blend limit exceeds 12%, the amount of ethanol blended as E85 never exceeds the consumption of ethanol in motor gasoline through 2022.

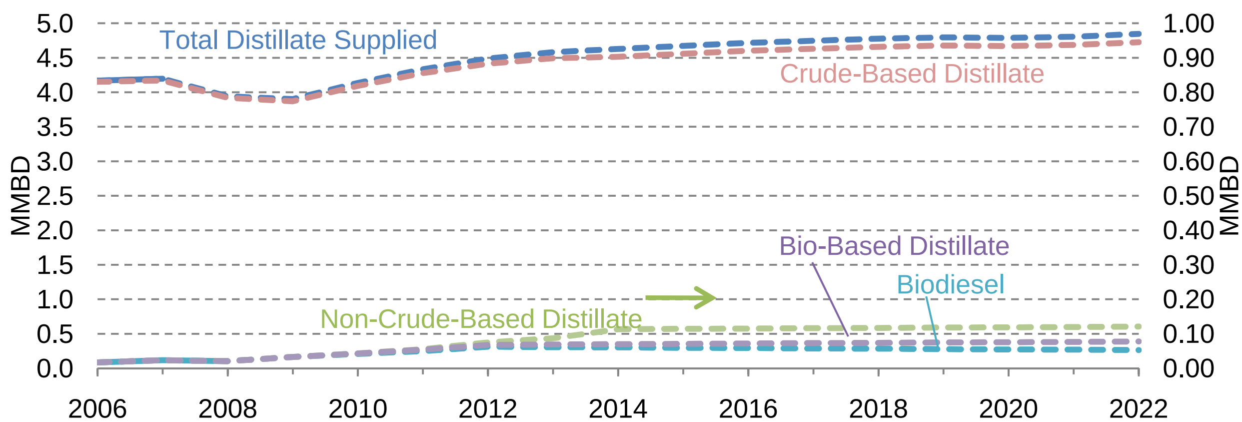


Figure 4-31. The AEO 2009 *lp* case has little impact on total distillate demand. Aside from a slight increase in total distillate demand, lower-crude prices cause total non-crude-based distillate consumption to fall due to reduced production of CTL. With equivalent bio-based distillate consumption, reduced CTL consumption, and increased total demand, crude-based distillate supplies nearly the entire distillate market through 2022.

As shown in Figure 4-27, total motor gasoline demand climbs above 10 MMBD in 2014. This demand exceeds 10.7 MMBD in 2022, compared to a demand of 9.5 MMBD in scenario 1. As total ethanol consumption increases with total demand, crude-based gasoline consumptions falls only slightly between 2012 and 2022, inching just below 8.5 MMBD in 2022. The E85 market expands at a slower pace as more crude-based gasoline is available for blending. By 2022, 60% of the ethanol supply is blended as E85 (see Figure 4-23). In 2022, ethanol supplies only 20% of the volume in the motor gasoline sector; this compares to 25% in scenario 5(a). Figures 4-29 and 4-30 show that increases in the blend limit have less overall impact on the transition, e.g., the 20% blend limit is reach in 2022, compared to 2020 in scenario 5(a). When the blend limit is increased beyond 13%, the amount of ethanol consumed as E85 never exceeds the consumption of ethanol in motor gasoline through 2022.

Aside from a reduction in CTL production, results for the DFO sector differ little from scenarios 1 and 5(a).

As illustrated by scenarios 5(a) and (b), the impact of the RFS program is dependent on total liquid fuels demand. Regardless of total demand, the RFS program mandates the same volumes of biofuels. When total demand falls, the liquid fuels sector undergoes a more rapid transition to biofuels, as evidenced by the rapid growth of the E85 market and sharp decline in demand for crude-based gasoline in scenario 5(a). When total demand increases, the transition unfolds more slowly, and demand for crude-based fuels remains strong. This later point is illustrated by the steady demand for crude-based gasoline in scenario 5(b).

In the next section, by revisiting each of the above scenarios, analysis will show that not only do transition pathways face similar barriers, but each pathway, or scenario, faces unique barriers. These unique barriers, or challenges, can be viewed as a set of tradeoffs facing the liquid fuels sector as it undergoes a biofuels transition.

4.5 Analysis and Discussion

Margo Oge, Director of the EPA Office of Transportation and Air Quality (OTAQ), recently explained that the RFS mandate can be met in essentially three ways [180]: (1) increase the availability of E85 in the market in conjunction with increased production of FFVs; (2) lessen the "incompatibility hurdle" through the production of synthetic fuels, or more compatible fuels, e.g., biobutanol, renewable diesel, renewable gasoline; or (3) increase the ethanol blend limit.

These three pathways are reflected in the scenarios presented in section 4.4. Scenario 1, which is based on the EPA control case volumes, requires an increased consumption of E85 in the market. Scenario 2, which is also based on the EPA control case, is reflective of the third pathway suggested by Oge, requiring an increase in the ethanol blend limit. Oge's second pathway could play out like scenarios 3(a), 3(b), or 4, which are based on increasing the production of synthetic fuels that are compatible with existing infrastructure. Finally, scenarios 5(a) and (b), illustrate the first pathway suggested by Oge, but with altered total liquid fuels demand.

Each of these scenarios will require simultaneous technological and operational changes throughout the fuel supply chain, including logistics and supply of feedstocks, fuel production, distribution and retail networks, and end use (e.g., engine technologies). Like the historical transitions reviewed in chapter 2, the extent of these impacts will vary for each scenario. These impacts depend on the nature of the fuels produced to meet the mandate, the status of the blend limit, and the overall demand for liquid fuels, among other factors. Tables 4-6 and 4-7 list each of the biofuel transition scenarios for the motor gasoline and DFO sectors, respectively, with the infrastructure implications of each scenario compared to the base case (i.e., scenario 1). The comparisons indicate whether the impacts to a particular segment of the supply chain will be greater than (+), less than (-), or approximately unchanged (~) when compared to the base case, along with a brief explanation of why the impacts differ relative to the base case.

The infrastructure impacts (and barriers) associated with the base case are discussed first, followed by a review of the remaining scenarios, highlighting how the impacts might differ in each case.[55]

[55] Recall from the introduction of this chapter (section 4.1) that feedstock production and logistics are omitted from the scope of this analysis.

Table 4-6. Infrastructure implications in the MoGas sector are qualitatively compared to the base case for each scenario.

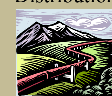
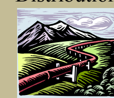
Sector	Transition scenario	Description	Ethanol, E85 (MMBD) in 2022	Infrastructure Implications				
				Production 	Refining 	Distribution 	Retail 	End use 
Motor Gasoline	Scenario 1	RFS compliance base case	2.227, 2.000	-	-	-	-	-
	Scenario 2	Increased ethanol blend limit (20%)	2.227, 0.615	(~) Same feedstock requirements	(~) Same ethanol production capacity required	(-) Ethanol needed for E85 blending reduced; less E85 storage capacity required	(-)/(~) E85 sales reduced, but still need to retail multiple blends	(-) Reduced E85 consumption (fewer FFVs)
	Scenario 3(a)	Increased bio-based distillates	1.500, 0.902	(-) Less cellulosic ethanol feedstock demand	(-) Less cellulosic ethanol fuel demand	(-) Less ethanol (and total motor gasoline volume) to distribute	(-) Ethanol blend sales reduced	(-) Reduced E85 consumption (fewer FFVs)
	Scenario 3(b)	Increased bio-based distillates (2)	0.978, 0.114	(-) No cellulosic ethanol feedstock demand	(-) No cellulosic ethanol fuel demand	(-) Less ethanol (and total motor gasoline volume) to distribution	(-) Ethanol blend sales reduced	(-) Minimal E85 consumption required
	Scenario 4	Renewable gasoline	1.183, 0.425	(~) Cellulosic feedstock still needed for renewable gasoline production (i.e., BTL)	(+) Renewable gasoline commercial production technologies come online	(-) Less ethanol (and total motor gasoline volume) to distribute	(-) Ethanol blend sales reduced, as ethanol is replaced by synfuel	(-) Reduced E85 consumption (fewer FFVs)
	Scenario 5(a)	Decreased liquid fuels demand	2.227, 2.090	(~) Same feedstock requirements	(~) Same ethanol production capacity required	(+)/(~) Ethanol needed for E85 blending increased; more E85 storage capacity	(+) E85 sales increase (more retail station conversions/upgrades)	(+) Increased E85 consumption (more FFVs and fleet turnover)
	Scenario 5(b)	Increased liquid fuels demand	2.227, 1.804	(~) Same feedstock requirements	(~) Same ethanol production capacity required	(-)/(~) Ethanol needed for E85 blending reduced; less E85 storage capacity	(-) E85 sales decrease (less retail station conversion/upgrades)	(-) Reduced E85 consumption (fewer FFVs or fleet turnover)

Table 4-7. Infrastructure implications in the DFO sector are qualitatively compared to the base case for each scenario.

Sector	Transition scenario	Description	Bio-based, crude-based distillate (MMBD) in 2022	Infrastructure Implications				
				Production 	Refining 	Distribution 	Retail 	End use 
Distillate Fuel Oil (DFO)	Scenario 1	RFS compliance base case	0.078, 4.426	-	-	-	-	-
	Scenario 2	Increased ethanol blend limit	0.078, 4.426	(~) Ethanol blend limit does not impact the DFO sector				
	Scenario 3(a)	Increased bio-based distillates	0.804, 3.733	(+) Cellulosic diesel (i.e., BTL) feedstock demand	(+) BTL commercial production technologies come online	(+) Distribution of bio-based distillate (compatible, but spatially dispersed supply)	(~) Sales of bio-based distillate increase (but compatible)	(~) Increased consumption of bio-based distillate (but compatible)
	Scenario 3(b)	Increased bio-based distillates (2)	1.326, 3.236	(+) Increased cellulosic diesel feedstock demand	(+) BTL commercial production technologies fully displace cellulosic ethanol production	(+) Distribution of bio-based distillate (compatible, but spatially dispersed supply)	(~) Sales of bio-based distillate increase (but compatible)	(~) Increased consumption of bio-based distillate (but compatible)
	Scenario 4	Renewable gasoline	0.078, 4.426	(~) Production of renewable gasoline does not impact the DFO sector				
	Scenario 5(a)	Decreased liquid fuels demand	0.078, 4.365	(~) Same feedstock requirements	(~) Same bio-based distillate production capacity required	(+)/(~) Increased percentage of distribution activities devoted to bio-based distillate	(~) Increased sales percentage of bio-based distillate (but compatible)	(~) Increased percentage of bio-based distillate (but compatible)
	Scenario 5(b)	Increased liquid fuels demand	0.078, 4.726	(~) Same feedstock requirements	(~) Same bio-based distillate production capacity required	(-)/(~) Decreased percentage of distribution activities devoted to bio-based distillate	(~) Decreased sales percentage of bio-based distillate (but compatible)	(~) Decreased percentage of bio-based distillate (but compatible)

4.5.1 Scenario 1: RFS compliance base case

Based on the EPA control case, this scenario aligns well with the pathway envisioned and analyzed by the EPA. This biofuels transition scenario requires greater volumes of ethanol consumption in the motor gasoline sector, with little increase in bio-based distillate consumption in the DFO sector. The changes required throughout the supply chain are discussed below, beginning with fuel production.

4.5.1.1 Fuel production

As ethanol consumption increases, the petroleum refining industry will be required to adapt as less demand for its number one product, gasoline, falls. As crude-based fuel demand shifts from gasoline to distillates, refiners could face the need to adjust operations away from a product slate currently optimized for gasoline production. Overall crude-based fuel demand could also fall, forcing refiners to make decisions related to refining capacity, possibly facing the need to shut down some current refineries [93]. These impacts are not isolated to U.S. refiners. As the gasoline market shrinks in the U.S., EU refiners could be faced with a shrinking export market [166]. The "peak gasoline" phenomenon could have other, far-reaching implications. For instance, as gasoline-tax revenues fall with demand, state and local government will be forced to search for new funding sources. Otherwise, basic services such as road repair could be impacted [93]. Since biofuels are currently supported with federal subsidies (through tax credits), the increased consumption of ethanol in the motor gasoline sector does little to offset reductions in gasoline-tax revenues.

As the industry sees its market share eroded by increased biofuels consumption, some companies will choose to enter the biofuels industry. There is already ample evidence of this trend. In March 2009, Valero, an independent oil refiner based in San Antonio, Texas, with plants and offices throughout the U.S. and Canada, purchased 7 ethanol plants from the Chapter 11 bankruptcy of VeraSun Energy Corporation [93, 181]. Valero paid $477 million for the plants, which are located in South Dakota, Iowa, Minnesota, Nebraska, and Indiana. It was the first purchase of ethanol plants by a traditional refiner in the U.S. A spokesperson for the company explained that the purchase "represents a cost savings and a recognition on Valero's part that ethanol is going to be part of the fuel mix going forward" [181]. Several oil companies, rather than buying their way into the existing ethanol market, have formed internal renewable fuels departments and are reaching out to existing biofuel and biotechnology companies. As discussed in section 4.4.4.2, BP has partnered with DuPont to develop biobutanol production technologies [177, 182]. The oil giant has also paired with Verenium Corporation, a small biofuel and biotechnology company based in Cambridge, Massachusetts, to scale up Verenium's cellulosic ethanol technologies for commercial production. BP intends to build a $250 million, commercial-scale, cellulosic ethanol plant in Florida based on this technology. In addition to the DuPont and Verenium ventures, BP has also entered the sugar cane ethanol market in Brazil. The president of BP's Biofuels unit, Phil New, explains the company's reasoning for entering the biofuels sector as follows [182]: "We can see biofuels as being a really big potential reservoir…If the government is going to make a market happen, we need to be able to participate commercially in that market." Shell has initiated partnerships with a number of small companies working on cellulosic ethanol technologies, algae-derived biofuels, and renewable gasoline [182]. Chevron, ExxonMobil, and ConocoPhillips have also initiated biofuels research and development projects. Chevron has partnered with Weyerhaeuser to develop cellulosic ethanol from wood waste [182]; ExxonMobil has launched a new program with Synthetic Genomics Inc. to produce biofuels from algae [183, 184]; ConocoPhillips ran a pilot project in 2008 using rendered animal fats produced by Tyson [12].

These examples serve as just a sampling of how the oil industry is venturing into the biofuels industry. As biofuels are increasingly mandated in the petroleum-dominated liquid fuels sector, these oil companies want to ensure that they are around to supply that market. In addition, the biomass feedstocks used to produce biofuels represent a new source of energy to replace any decline in crude oil production that could occur in the future.

In the base case scenario, cellulosic ethanol production technology must be scaled up to produce 100 mgy in 2010, increasing to 16 bgy in 2022. Cellulosic ethanol is produced from lignocellulosic feedstocks, including forestry and agricultural residues (e.g., wood chips, corn stover), cover crops, perennial "energy" crops grown on marginal lands, and other waste streams (e.g. municipal solid wastes). By avoiding agricultural food commodities, the production of cellulosic ethanol has the potential to overcome some of the problems associated with conventional (corn) ethanol production, e.g., competition with food and feed supplies, water consumption, land use change, etc. Ethanol can be produced from cellulosic feedstocks through a number of biochemical and thermochemical processes. Compared to conventional ethanol production, cellulosic production technologies are more complex technologically, requiring additional processing steps and process inputs. Detailed information and analyses of cellulosic feedstocks and biofuel production technologies are readily available in the literature [10, 25, 105, 118, 144, 145, 167, 185-192].

A panel convened by the National Research Council (NRC)—America's Energy Future Panel on Alternative Liquid Transportation Fuels—assessed the current state of cellulosic ethanol production technologies and made several recommendations for promoting its development and eventual deployment on a commercial scale [105]. Overall, the panel judged that cellulosic ethanol will be capable of commercial deployment before 2020, but not necessarily at the scale of 21 bgy. To gain the engineering and operational knowledge needed to reduce capital and operating costs of commercial-scale production facilities, the panel recommends that the federal government and industry pursue technology demonstration and small-scale commercial plants, which would provide detailed engineering and cost performance data. In tandem, processes specific to the production of cellulosic ethanol (e.g. feedstock pretreatment, enzymatic hydrolysis, fermentation, etc) need to be improved to reduce plant-level costs. The panel recommends that the federal government continue its support of research and development (R&D) of cellulosic ethanol technology, with program design and resource allocation based on a long-term perspective. In addition, the R&D programs should be coupled with the pilot- and commercial-scale demonstrations and deployments to ensure that appropriate industrial-level issues are being addressed and new technologies are being continuously demonstrated.

Currently, there are no commercial-scale cellulosic ethanol production facilities in the nation [25]. However, several pilot scale projects are underway, or have been announced, along with plans and proposals to build commercial scale facilities in the near future.[56] The execution of these plans will hinge on the successful development of production technologies and the financing of the construction and operation of new facilities. Based on an assessment by the EPA, there were 25 small cellulosic ethanol plants operating in April 2009, although most produce insignificant volumes of ethanol on an irregular basis. In order to meet the cellulosic biofuel mandate, production facilities will have to be financed and built at a rapid pace. The EPA, in their control case analysis, developed one scenario for building plants that would meet the annual cellulosic mandate. Figure 4-32 shows the required build rate and annually increasing ethanol industry capacity compared to the historical and ongoing build rate of conventional, starch ethanol plants [25]. The EPA scenario calls for 2-10 plants per year (40 mgy average capacity) from 2010-2013; 10-18 plants per year (80 mgy) from 2014-2017; and 20 plants per year (100 mgy) through 2022. This scenario produces a total cellulosic ethanol capacity of 16 bgy distributed among 186 facilities in 2022. In 2008, conventional plant construction peaked at 27 plants with an average capacity of 100 mgy. Based on present and planned future capacity, there will be 163 conventional plants producing 15 bgy. The National Commission on Energy Policy (NCEP), a bipartisan group of energy experts, suggests that 60-100 new cellulosic biorefineries with 30-50 mgy capacity each are needed by 2015, and 300-500 by 2022, or approximately 25-45 new facilities per year through 2022 [193].

---

[56] The reader is referred to sections 1.4.3 and 1.5.3 of the EPA RFS2 DRIA. See http://www.epa.gov/otaq/renewablefuels/420d09001.pdf

When compared to the historical build rate of conventional plants, the cellulosic build rate is not unreasonable. However, cellulosic plants are to be based on technologies that have yet to be proven on a commercial scale, and will be run on feedstock supplies that are currently not produced, collected, stored, and distributed on a wide scale. The conventional ethanol industry has had the advantage of developing around a feedstock (i.e., corn) that is already produced, collected, stored, and distributed on a large scale. The logistics of siting these new plants also serves as a source of uncertainty. According to the NCEP, inbound and outbound transportation costs can amount to 20% of operating costs for biorefineries. Strategic siting of these facilities is dictated by proximity to transportation infrastructure (e.g., railroad) and feedstock radius (the maximum distance that feedstock is collected and transported to a given facility) [193].

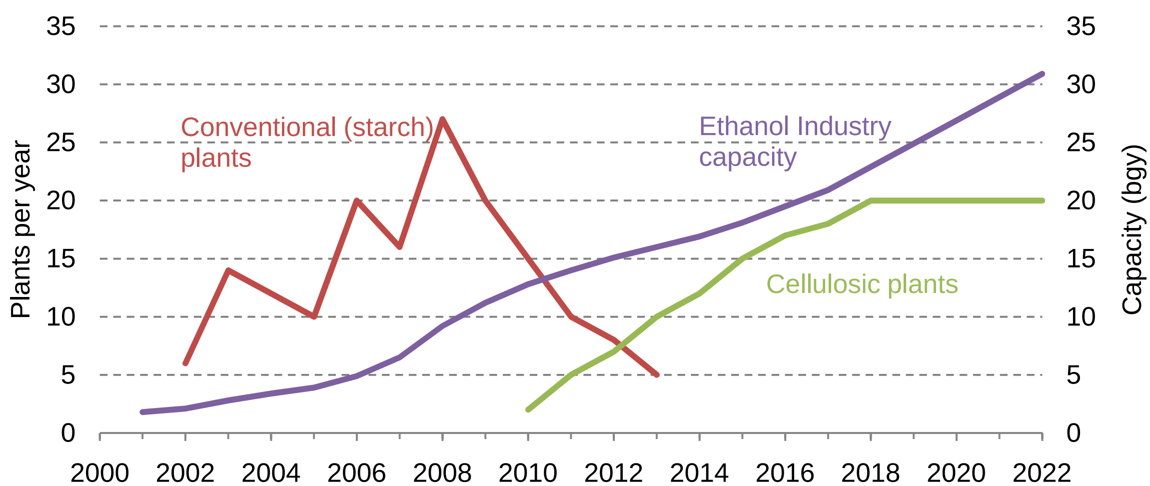


Figure 4-32. The EPA control case requires ethanol capacity to expand with the construction of cellulosic ethanol plants starting in 2010 and continuing through 2022 [25]. As discussed in section 1.3, the capacity of existing and proposed conventional facilities and those currently under construction is approximately 15 bgy, which is equivalent to the limit on conventional biofuels production imposed in 2015 by the RFS.

The EPA control case also foresees the need for increased imports of ethanol, increasing from 500 mgy in 2008 to over 3 bgy in 2022 [25]. Currently, the U.S. stands as the top producer of ethanol in the world, followed closely by Brazil. In 2008, the U.S. produced 9.2 billion gallons of ethanol, while Brazil produced approximately 6.5 billion gallons. The next closest producer is the EU, which produced well under 1 billion gallons in 2008 [194]. The additional demand for ethanol imports by the U.S. from 2008 through 2022 alone would force Brazil to increase production by nearly 40%. When considering future demand for transportation fuels in Brazil, increased global demand for biofuels, and the current excise tax levied on ethanol imports to the U.S., the ability to secure an additional 2.5 bgy of ethanol imports stands as a major source of uncertainty in this scenario.

The NCEP cites state-specific fuel requirements and formulations as another source of uncertainty as ethanol consumption increases with the RFS mandate [193]. Currently, refiners that supply liquid fuels to the U.S. liquid fuels sector face a plethora of fuel standards, typically dictated by state and federal air quality requirements. For example, as discussed in chapter 2, the CAA mandates the use of reformulated gasoline (RFG) in several metropolitan regions in the U.S. Another example is the wintertime oxyfuel program, requiring gasoline supplied in the winter months to have increased oxygenate content as a means for reducing CO emissions. Figure 4-33, a map published in April 2007 by ExxonMobil, illustrates the geographical diversity of gasoline formulation requirements throughout the nation [195]. As ethanol penetrates the motor gasoline sector, and is blended in ever greater quantities throughout the nation's gasoline supply, refiners and blenders could face challenges in meeting the requirements of these various state-level fuel specifications and emission requirements. Refiners will be required to produce gasoline blend stocks (i.e., the crude-based gasoline blended with ethanol) that still meet the specifications even as the amount of ethanol blended into the gasoline supply increases. Meeting these requirements could reduce production and distribution efficiencies, ultimately impacting costs. The NCEP suggests that some level of federal harmonization of fuel specifications could help to alleviate these challenges [193].

The remaining fuels produced in scenario 1 include limited quantities of biodiesel and other bio-based distillate, i.e., renewable diesel produced at standalone facilities or co-processed at existing crude oil refineries. Both fuels are produced from triglycerides (e.g., vegetable oils, rendered fats, waste grease, etc). The EPA limits the role of these fuels based on an assumption that the supply of bio-based oil feedstocks (i.e., triglycerides) will remain tight due to demand for other uses, e.g., food, over the span of the RFS program. Unless new, "advanced" feedstock sources, like algae, are developed in the near term, these fuels will continue to supply a minimal portion of the DFO sector [25]. Increased consumption of bio-based distillate in the DFO sector is discussed further in section 4.5.3.

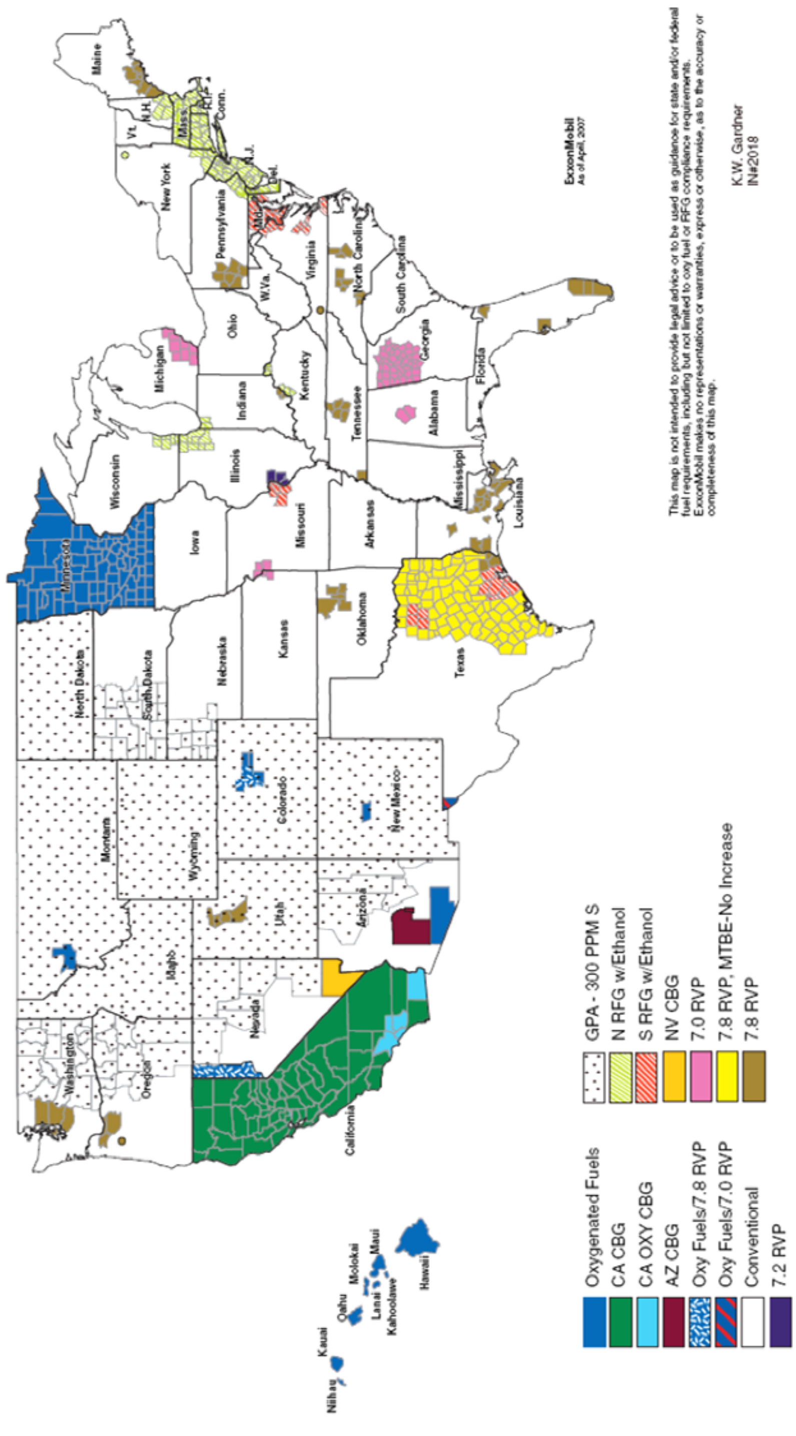


Figure 4-33. A map of U.S. gasoline requirements illustrates the geographic diversity of gasoline fuel formulations [195].

4.5.1.2 Distribution

In scenario 1, ethanol comprises more than 90% of annual biofuels volume that must be distributed to end use markets through 2022. Currently, the majority of ethanol is produced in over 100 facilities scattered across the Midwest and Great Plains, i.e., the corn belt.[57] Ethanol is distributed from these geographically dispersed distilleries to the retail market through a "virtual pipeline" comprised of train, barge, and truck transportation networks. Currently, about 60% of ethanol is transported by rail, 30% by truck, and 10% by barge [196]. The demands placed on this "virtual pipeline" will only increase with further increases in ethanol production [25, 71, 193, 197]. The NRC panel (i.e., America's Energy Future Panel) explains the challenge as follows [105]:

> The need to expand the delivery infrastructure to meet a high volume of ethanol deployment could delay and limit the penetration of ethanol into the U.S. transportation fuels market. Replacing a substantial proportion of transportation gasoline with ethanol will require a new infrastructure for its transport and distribution. Although the cost of delivery is a small fraction of the overall fuel-ethanol cost, the logistics and capital requirements for widespread expansion could present many hurdles if they are not planned for well.

This problem is exacerbated by the fact that ethanol has a lower energy content relative to the crude-based gasoline it replaces. So, as ethanol increasingly displaces crude-based gasoline, the overall volume of fuel that must be distributed is greater than a business-as-usual scenario that would see little to no growth in ethanol consumption. So, unless total motor gasoline demand falls, the displacement of crude-based gasoline with ethanol will alone require the distribution infrastructure to expand from present-day capacity.

Researchers at the Oak Ridge National Laboratory (ORNL) recently studied the distribution challenges associated with increasing production of ethanol based on the

[57] See section 1.3.

EPA control case (i.e., increasing to 34.14 bgy in 2022). They introduced the problems as follows [196]:

> At current levels of shipments, biofuels represent less than 1% of total railcar ton-miles shipped in the United States. It is anticipated that renewable fuels are unlikely to have more than marginal impact on rail capacity or congestion. However, the rail system itself is subject to increasing capacity and congestion constraints that will impact all commodities shipped by rails, including biofuels. A lack of rail accessibility at biorefinery sites, the type of rail infrastructure accessible to biofuels producers, the current state of capacity and congestion on the U.S. rail network, and logistics and supply-chain management capabilities at biofuels producers are some of the issues related to the U.S. rail system that need to be addressed.

Using an infrastructure network model, the ORNL researchers analyzed the transportation of ethanol by domestic rail, barge, and truck distribution systems from ethanol plants to blending terminals. The analysis did not account for increased distribution activity associated with feedstock collection and transportation to biorefineries, and distribution of blended fuels from terminals to retail stations. They computed increases in spatially-resolved transportation activity (e.g., kton-miles); state-by-state and national average distribution costs; and rolling stock requirements (i.e., number of railcars, barges, and trucks) in 2022. A "distribution constraint analysis" was conducted to assess where stresses (e.g., delays due to increased congestion) in the distribution infrastructure could potentially arise due to the increased biofuels demand. The study found that ethanol shipments would continue to be moved predominantly by rail, increasing to approximately 90% in terms of ton-mile movements in 2022. Since biofuels make up only a small portion of overall movement of goods through the distribution infrastructure, demand in 2022 is expected to increase ton-mile movements by rail, barge, and truck by only 2.8%, 0.6%, and 0.13%, respectively, when compared to 2005 shipments. The national average ethanol distribution cost was estimated to be 6.8 cents/gallon in 2022, with state-by-state estimates ranging from 1.2 to 33.2 cents/gallon. In summary, the researchers found that future ethanol demand would have minimal impacts on transportation infrastructure overall. But, spatial impacts due to increases in rail traffic would require a significant level of investment. The assumed locations of biorefineries and distribution (i.e., blending) terminals were found to have significant impacts on transportation activity and distribution costs [196].

As the "virtual pipeline" continues to expand with ethanol production, railcar production could become a major constraint. It is estimated that 60-65% of new rail tank car orders are currently due to increased ethanol demand [196]. According to Roger Ginder, professor of economics at Iowa State University, production backlogs for railcars have risen by approximately 400% since 2005, while production output has remained nearly flat. Ginder explains the problems as follows [198]:

> There are four major tank car manufactuers—GATX, Trinity, Union, and AFT…Some car manufacturers are booked for more than two years. Until growth in [ethanol] production capacity slows and/or turnaround times for ethanol tank cars increases, it will be difficult to reduce the backlog in orders.

A growing reliance on the rail, barge, and truck distribution systems is based on the assumption that pipelines will not be used to move any substantial amount of ethanol. If pipelines became an option for distributing ethanol, and other biofuels, then a Gulf Coast hub to collect and distribute biofuels, similar to today for petroleum-based fuels, could be favored, reducing impacts on the wider distribution system and reducing ethanol distribution costs [193, 196]. However, ethanol is typically not used in pipelines for several reasons [193, 199, 200]:

- hygroscopic/hydrophilic nature of ethanol;
- tendency of water to separate from ethanol when blended with gasoline;
- potential for stress corrosion cracking of steel;
- compatibility with polymers used for pipeline coatings;
- compatibility with elastomers used for seals and gaskets;
- compatibility with drag-reducing agents;
- potential for mixing and reacting with other products delivered through pipelines.

The petroleum pipeline infrastructure was developed around an oil refining industry that is predominantly concentrated around the Gulf Coast region (e.g., Texas and Louisiana), and delivers finished products to major demand centers on the East and West Coasts. If the disadvantageous properties of ethanol are put aside, addressing the geographic disparity between the current ethanol supply and existing pipeline infrastructure becomes a major logistical problem. However, these problems have not mitigated interest in integrated and moving ethanol through pipelines. Like oil producers, distribution companies have interest in moving new fuels through their systems as demand for conventional petroleum products declines. In section 2.4.3, examples highlighting this interest were discussed. For example, Kinder Morgan ran trial shipments of ethanol, ethanol blends, and biodiesel blends in existing pipelines in Florida and the Southeast, and proceeded with commercial shipments of ethanol in Florida and announced plans to distribute biodiesel blends in the Southeast [98, 99, 201]. Other pipeline and distribution companies and industry groups are conducting research on the transport of ethanol and other biofuels through existing pipelines [199, 202]. Even if this research enables distributors to overcome compatibility barriers, the question of geographic disparity and logistics remains.

Magellan Midstream Partners and POET, taking a different approach, are jointly conducting a feasibility study of building a dedicated ethanol pipeline from the Midwest to demand centers in the Northeast [101]. A map of the currently proposed pipeline is shown in Figure 4-34. This approach could address both the compatibility concerns with existing pipelines and the geographic disparity between existing pipeline networks and ethanol facilities. A dedicated ethanol pipeline will face significant barriers related to capital costs, the need to gather sufficient throughput from dispersed ethanol producers, and siting issues [200]. Robust markets and guaranteed long-term supply is needed to justify the financing of such a large-scale project. The siting of a dedicated ethanol pipeline would likely require eminent domain authority. According to the NCEP, this authority currently does not exist for ethanol pipelines [193]. Due to long permitting and right-of-way acquisition lead times, the NCEP believes that a decision to build a dedicated ethanol pipeline cannot be delayed beyond 2009, if pipeline distribution is to play a role in moving ethanol produced under the RFS.

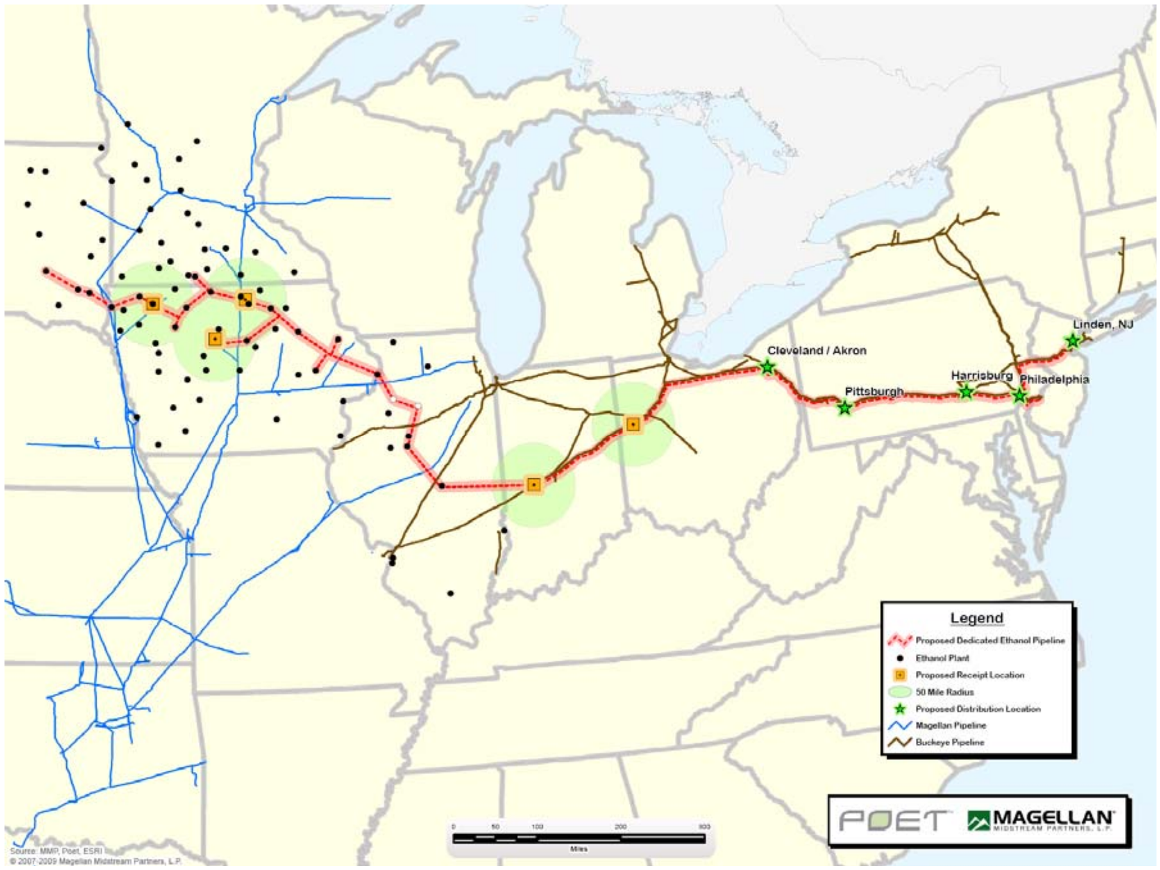


Figure 4-34. Magellan and POET are studying the feasibility of constructing and operating a dedicated ethanol pipeline, as illustrated in this map [203]. The red-dashed line represents the proposed pipeline; solid-blue lines represent existing Magellan pipelines; solid-brown lines indicated existing Buckeye pipelines; yellow squares represented proposed ethanol receipt locations, surrounded by green circles indicating a 50 mile radius; black dots represent ethanol plants; and green stars are proposed distribution locations.

Distribution infrastructure could also be influenced by the development of the cellulosic ethanol industry. If new cellulosic ethanol plants are widely distributed across the nation, rather than being developed around existing facilities in the Midwest, then distribution on a regional or local scale could be more efficient. If the new facilities are sited near existing corn ethanol plants (e.g., to utilize corn stover and cover crops as feedstocks), then the dedicated pipeline route becomes more viable [193]. However, with cellulosic ethanol production technology under development, it is not clear what feedstocks will be favored by the industry.

To address the distribution challenges associated with the deployment of increasing volumes of ethanol, the NRC panel recommends the following:

> The U.S. DOE and the biofuels industry should conduct a comprehensive joint study to identify the infrastructure system requirements of, research and development needs in, and challenges facing the expanding biofuels industry.

Like the NCEP, the NRC panel stresses that the continued expansion of the "virtual pipeline" and the long-term potential of this system to accommodate increasing volumes of ethanol should be weighed against the potential benefits of pipeline delivery (dedicated or otherwise). Results from the ORNL study suggest that the "virtual pipeline" is capable of accommodating the increased volumes of ethanol and other biofuels. However, this analysis was based on the assumption that pipelines would not be an option. An analysis including that includes the pipeline option could help to address questions related to the use of pipelines in distributing ethanol in the future.

The NRC panel also recommends that any analysis of biofuels distribution should account for the "timing and role of advanced biofuels that are compatible with the existing…infrastructure." Scenarios 3 and 4, which are based on the increased production of advanced biofuels, serve to illustrate the impacts of shifting to biofuels that are compatible with existing infrastructure. These impacts are discussed further in section 4.5.3.

4.5.1.3 Retail and End Use

The retail and end use segments of the fuel supply chain could be addressed separately, but, as will be discussed, these segments face some barriers that must be overcome in unison. Again, with ethanol serving as the predominant fuel in this scenario, the focus here is on the implications of storing and dispensing increased volumes of ethanol in the retail network, and the consumption of ethanol in motor-gasoline-powered vehicles.

In scenario 1, the motor gasoline sector is comprised of E10 and E85. As the 10% blend limit is approached, and ultimately reached, the retail network must be prepared to supply the market with an increasing volume of E85. Unlike E10, which is currently dispensed as conventional motor gasoline nationwide, E85 requires retailers to install new, or upgrade existing, storage and dispensing equipment. Since total motor gasoline demand is not expected to grow substantially through 2022, the supply of E85 will be moved predominantly through existing facilities. In 2008, the National Renewable Energy Laboratory (NREL) conducted a survey and literature review to assess the costs associated with adding E85 equipment to existing gasoline stations [29]. Table 4-8 shows the results of the NREL study. The first scenario, which involves the installation of a new storage tank and new or retrofit dispenser(s), is estimated to cost between $50,000 and $200,000. The second scenario, involving the conversion of an existing storage tank and installation of new or retrofit dispenser(s), is estimated to cost much less, ranging from $2,500 to $30,000. The table summarizes the major variables that influence the cost for each scenario, e.g., the number of dispensers, excavation and concrete work, etc. In 1978, it was estimated that the cost incurred by retail stations that made unleaded conversions was $5,951 per station [29]. In 2009 dollars, this cost equates to approximately $20,000, falling well within the range of costs to convert an existing tank to store E85. However, the NREL report explains that a declining number of stations could pursue this option (i.e., the second scenario), shifting the majority of E85 upgrades to the new tank scenario. The conversion option is only viable if a gasoline station can economically justify switching an existing tank to E85. With an average of

3.3 tanks per station, most retailers would be challenged to justify such a conversion, depending on the sales of fuels currently dispensed (e.g., premium, diesel, etc) relative to expected E85 sales. If retailers are not guaranteed a robust E85 market, then justifying the costs to add E85 equipment becomes a major challenge.

Table 4-8. The NREL compiled cost estimates for adding E85 equipment to existing gasoline stations, based on two scenarios: (1) adding a new tank and new or retrofit dispenser(s) and (2) converting an existing tank and installing new or retrofit dispenser(s) [204].

Scenario	Estimated Cost	Description	Major Variables Affecting Cost
New tank, new or retrofit dispenser(s)	\$50,000-\$200,000	Includes new storage tank, pump, dispenser(s), piping, electrical wiring, excavation, and concrete work	Dispenser needs, excavation, concrete work, sell backs, canopy, tank size, location, labor price, regulations/permitting
Convert existing tank, new or retrofit dispensers	\$2,500-\$30,000	Tank cleaning, replace non-compatible components in piping and dispensers	Dispenser needs, number of non-compatible components, location, labor price, regulations

Once retail stations decide to add E85 storage and dispensing equipment, either through new or converted equipment scenarios, the question of pricing must be addressed. Due to the lower energy content of ethanol, E85 has, on average, 22% less energy per gallon than E10. Assuming that this reduction in energy content per gallon translates directly into a 22% reduction in fuel economy for the end user, then the E85 sale price must be reduced to ensure "price parity" with E10. Table 4-9 presents the energy content of gasoline, ethanol, and various blends, along with example pricing to ensure price parity among fuels (based on equivalent energy content per unit cost). If the average price of straight crude-based gasoline is \$2.59, E10 must be priced at \$2.50, and E85 at \$1.94 to ensure price parity. The table shows the required price spread as a percentage, which can be used to determine pricing parity as the price of fuels fluctuate. Figure 4-35 illustrates this trend graphically. As the average content of ethanol in motor gasoline reaches the 10% limit, the price spread would be based on the difference in price spreads for E10 and E85 (-22%) to ensure pricing parity (since straight crude-based gasoline, E0, would be unavailable at most retail stations). Since January 2009, the price spread between motor gasoline and E85 has fluctuated between 9% and 19%, and currently stands at approximately 14.5% [205].

The pricing parity argument could be extended beyond a simple energy content argument. Due to the reduced energy content, and accompanying reduction in fuel economy, consumers choosing to fill up with E85 will be faced with more frequent trips to the refueling station. To compensate for this increased frequency of refueling, consumers could demand additional incentives, e.g., further reductions in E85 pricing. As discussed in chapter 2, Borenstein estimated that the price differential between leaded and unleaded gasoline slowed the phase out of leaded gasoline by about 4 years (Figure 2-2 shows that unleaded gasoline was priced higher than leaded gasoline throughout the 15 year lead transition). This historical example suggests that the relative pricing of fuels could influence the transition to biofuels.

Table 4-9. To ensure price parity, the price of ethanol-gasoline blends must fall relative to crude-based gasoline as the ethanol content increases. The LHVs of gasoline and ethanol are taken from Table 4-4.

Fuel	LHV (Btu/gallon)	Example retail price	Price relative to gasoline	Price spread
gasoline	115,261	$ 2.59	$ -	0%
ethanol	76,330	$ 1.72	$ (0.87)	-34%
E85	86,452	$ 1.94	$ (0.65)	-25%
E10	111,368	$ 2.50	$ (0.09)	-3%
E15	109,421	$ 2.46	$ (0.13)	-5%
E20	107,475	$ 2.42	$ (0.17)	-7%

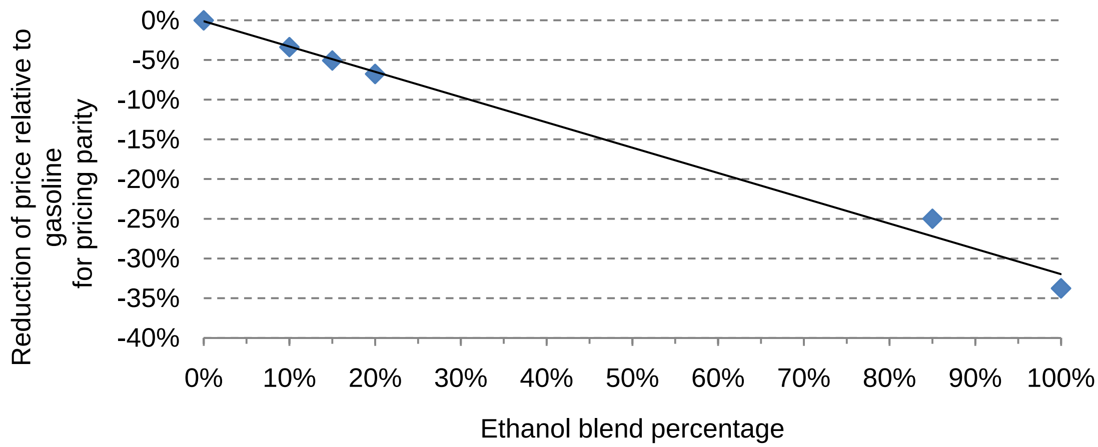


Figure 4-35. The price of ethanol blends must be reduced as the ethanol content increases in order to ensure price parity. The trend is not a perfectly linear relationship due to the seasonally-average content of ethanol in E85 (i.e., 74%).

Even if retail stations make the appropriate upgrades to store and dispense E85, and adjust pricing to incentivize purchases of the new fuel, end users must have equipment that is capable of operating on E85. The availability of vehicles capable of operating on higher-blends of ethanol (and customer demand for such vehicles) is a major source demand uncertainty [193]. Due to the physical and chemical properties of ethanol, gasoline-powered vehicles must be modified to operate on higher blends, such as E85. Systems requiring modification, and the extent of modifications, are dependent on the blend level and age of vehicle, as illustrated in Figure 4-36.

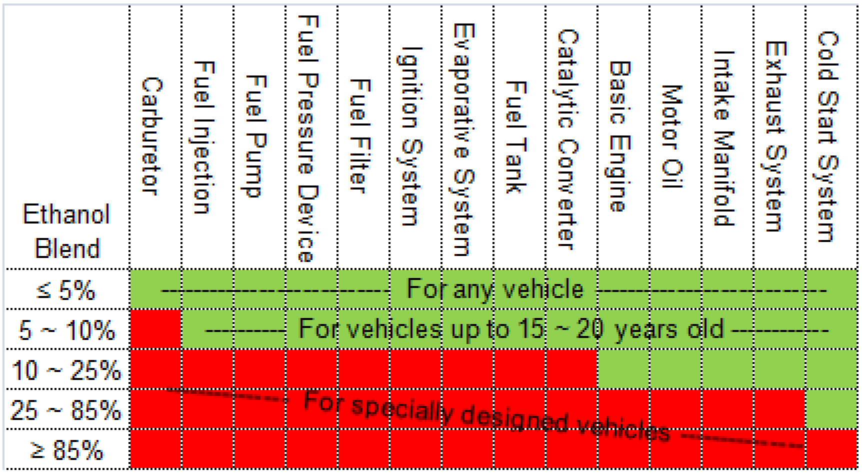


Figure 4-36. Vehicle and engine systems requiring modification depend on the ethanol blend level and vehicle age. Modifications are not necessary in boxes shaded green; modifications are probably necessary in red areas. For example, vehicles that are 15-20 years old probably require modifications to the carburetor when operating on blends greater than 5% [192, 206].

Since scenario 1 is based on a motor gasoline sector supplied with E10 and E85, the only rows in Figure 4-36 that are of concern include ethanol blends up to 10% and blends greater than or equal to 85%. Aside from vehicles equipped with carburetors, fueling with E10 poses no challenges to the existing fleet of gasoline-powered vehicles. The remaining fuel, E85, must be consumed by specially designed vehicles, or flex-fuel vehicles (FFVs). Ford Motor Company explains that the following components and systems must be modified when upgrading an existing vehicle model to be flex-fuel capable [207]:

- Engine components, including valves, valve seats, spark plugs, fuel injectors, direct-injection fuel pumps, cylinder head gaskets;
- Adjustment of controller calibrations for performance, emissions, on-board diagnostics (OBD), and cold start (at all blend levels);
- Fuel system components, including fuel tank, flow pump, fuel delivery lines.

In addition to component modifications and calibration adjustments, evaporative and emissions testing procedures become more challenging in the development and certification testing process.

Currently, vehicle manufacturers do not warrant the use of blends exceeding E10 in conventional (non-flex-fuel) vehicles, coinciding with the limit imposed on motor gasoline by the CAA. However, domestic vehicle manufacturers have been producing flex-fuel vehicles (FFVs) capable of operating on blends up to E85 since about 1996. Figure 4-37 shows the number of light-duty FFVs in use (i.e., rolling stock), along with cumulative production of light- and medium-duty vehicles, from 1996 through 2008. The rolling stock estimates are derived from cumulative production data using vehicle survivability factors published by the NHTSA [208]. In January 2008, approximately 6,250,927 FFVs were in operation in the U.S. LDV fleet. Figure 4-37 also plots EIA estimates of the number of FFVs actually fueled on E85 from 2003-2007 [209]. Due to the limited availability of E85 in the market, the vast majority of FFVs in use are not actually fueled with E85.

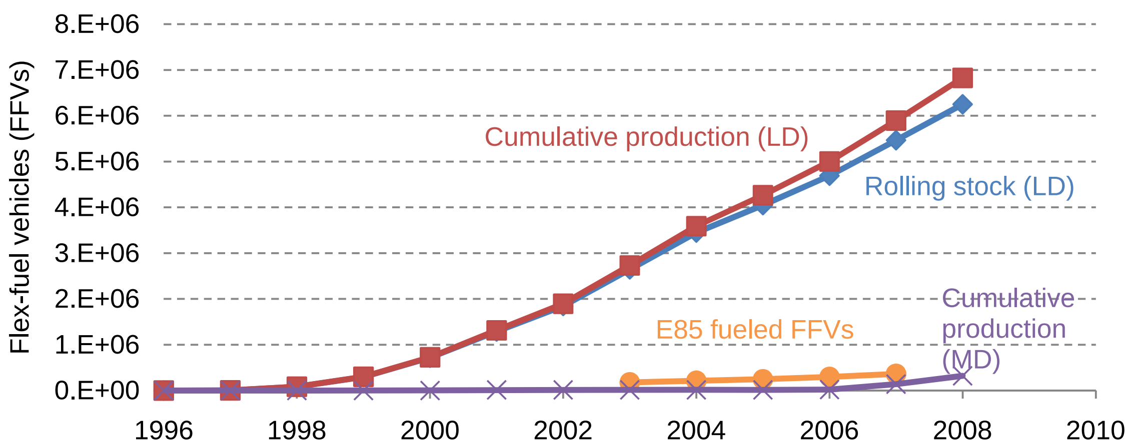


Figure 4-37. The cumulative production and rolling stock of light-duty FFVs have increased steadily since 1998 [208, 209]. Due to limited availability of E85, the vast majority of in-use FFVs are not fueled with E85.

The dynamics of fleet turnover influence the rate at which FFVs enter the market—turnover of the U.S. LDV fleet typically takes 15 years or more [102]. If all LDVs sold in the U.S. starting in 2010 were FFVs, nearly the entire LDV fleet would be capable of operating on E85 in 2025, at best. In scenario 1, E85's share of total motor gasoline (by volume) increases to just over 20% in 2022. In 2008, out of a total light-duty fleet of 232 million vehicles, 2.5%, or 6 million, were FFVs. The EIA projects that the total light-duty fleet will grow to 266 million in 2022 [210]. If E85 fuel is assumed to fuel all FFVs, i.e., all consumers with FFVs always choose to purchase E85, then approximately 16% of the light-duty fleet must be comprised of FFVs in 2022, i.e., 42 million.[58] Over a 14 year period, the FFV population must grow by 42 million, while the entire light-duty fleet grows by only 34 million. This fleet turnover seems feasible, but it is based on a very optimistic assumption related to refueling.

The continued production and sale of FFVs is highly uncertain. In the RFS2 DRIA, the EPA analyzed 3 scenarios based on different assumptions related to FFV production rates, forecasted vehicle phase-out (i.e., fleet turnover), vehicle-miles traveled, and fuel economy estimates [25]. Using the EPA MOVES model, EPA analysts estimated that the maximum percentage of motor gasoline fuel that could feasibly be consumed by FFVs in 2022 is 30%. The analysis further assumed that FFVs would be evenly distributed throughout the nation, and that access to E85 would not be a problem. However, the expansion of E85 infrastructure needed to ensure refueling access is also uncertain. The EPA defines "reasonable access" to E85 as one-in-four pumps offering the fuel in a given area.[59] The EPA estimated that reasonable E85 access must grow to encompass 70% of the nation by 2022.

In 2007, 164,292 conventional refueling stations were in operation in the U.S [211], and 2,204 stations currently offer E85 [205]. Assuming that the number of

[58] Due to the lower energy content of E85 relative to E10 (22% reduction), only 16% of the fleet could be exclusively fueled on E85.

[59] This definition is based on current access to diesel fuel, which is available at approximately one-in-four stations.

conventional stations has not dropped significantly in the past 2 years, then approximately 5% of the nation currently has reasonable E85 access, according to the EPA definition. If the number of stations remains steady[60] through 2022, then 26,547 additional stations would need to add E85 to their fuel offerings, or approximately 2,000 per year through 2022. If reasonable access is defined as one-in-three stations offering E85, then 36,131 additional stations, or approximately 2,800 stations per year must add E85 access through 2022. From 2007 through present day, the number of stations offering E85 has increased from 1,085 to 2,204, an increase of less than 600 stations per year. Based on these simple calculations, it is clear that E85 infrastructure must expand rapidly relative to recent growth in order to supply the market with sufficient access to and volume of E85 to meet the RFS mandate according to scenario 1, or the EPA control case.

Even if one-in-four stations offer E85 in 2022, the distribution of these stations relative to the distribution of FFVs in the LDV fleet remains uncertain. The NRC panel explains the problem that exists between the retail and end use segments as follows [105]:

> Expansion of the flexible-fuel vehicle fleet needs to be complemented by presence of ethanol stations close to where the vehicles are used. Past policy that mandated the increased use of alternative-fuel vehicles did not result in reduced gasoline consumption, because ethanol pumps were not readily available in many areas where flexible-fuel vehicles were used. The close coupling of alternative fuels and alternative-fuel vehicles is an important practical consideration.

The panel recommends that "[f]uture policy measures need to take into account implementation of alternative-fuel vehicles, availability of alternative fuels, and proximity of vehicles to fueling stations to ensure an effective vehicle and fuel transition." Therefore, even if FFVs penetrate the market, E85 availability in the retail sector (in terms of volume and access) could hinder total ethanol consumption by limiting expansion of the E85 market. A stand alone volume mandate, met primarily through E10

[60] The number of conventional refueling stations has actually declined steadily since the 1990s, falling from 207,416 in 1993 to 164,292 in 2007. See (Davis et. al, 2009).

and E85, could be hindered by a failure to address this coupling between the end use and retail segments of the fuel supply chain.

In chapter 3, several models were reviewed that examine this “chicken-and-egg” problem based on system dynamics and complex adaptive system methodologies. For example, the HyDIVE model, developed by NREL and MIT researchers, examines the spatial, behavioral, and market dynamics involved in the development of hydrogen as a transport fuel, with the objective of understanding barriers to simultaneous penetration of vehicle and fueling infrastructure. This modeling approach could be readily adapted to the same problem associated with the simultaneous penetration of FFVs and E85 fueling infrastructure.

Overall, scenario 1 will require significant capital investments throughout the fuel supply chain, from new production facilities (e.g., cellulosic and conventional ethanol), expanded biofuels distribution capacity, and upgraded retail stations coupled with an increased population of FFVs. The projected capital investments required over the life of the RFS program, as estimate by the EPA, are show in Table 4-9. Since scenario 1 is based on the EPA control case, which serves as the basis for the EPA analysis, these cost estimates are worth reviewing here. The EPA explains the estimated capital investments as follows:

> The increased use of renewable and alternative fuels would require capital investments in corn and cellulosic ethanol plants, and renewable diesel fuel plants. In addition to producing the fuels, storage and distribution facilities along the whole distribution chain, including at retail, will have to be constructed for these new fuels. Conversely, as these renewable and alternative fuels are being produced, they supplant gasoline and diesel fuel demand which results in less new investments in refineries compared to business-as-usual.

As shown in Table 4-10, nearly all investments are related to the expanded production and distribution of ethanol.

Table 4-10. The EPA estimated capital investments necessary over the life of the RFS program (based on the EPA control case, which is analogous to scenario 1) [25].

Investment type	Capital Costs (billion dollars)
Corn ethanol plants	4.0
Cellulosic ethanol plants	50.1
Ethanol distribution	12.4
Bio-based distillate production and distribution	0.25
Petroleum refining industry (avoided investments)	-7.9
Total	58.9

4.5.2 Scenario 2: Increased ethanol blend limit

In scenario 2, the ethanol blend limit is increased from the regulated level of 10% to 20%. As discussed in section 4.4.2, the current 10% limit was established by a waiver request under section 211(f) of the CAA [160]. The limit can be increased only through an amendment to the CAA or with the approval of another waiver request. The EPA is currently reviewing a waiver request to increase the blend limit to 15%, which was submitted on March 6, 2009 by Growth Energy, an ethanol industry advocacy group, and 54 ethanol producers. The EPA must make a decision to grant or deny the request by December 1, 2009 [25, 175]. [61]

The increased blend limit has been pursued as a means for incorporating more ethanol into the motor gasoline supply as the nation approaches the 10% limit in the coming years. The current rate of growth of E85 infrastructure and population of FFVs in the light-duty fleet may be insufficient to incorporate the growth in ethanol supply needed to meet the RFS. As shown in Figure 4-12, increasing the blend limit delays the year in which the blend limit is reached, delaying the need for E85 to supply a portion of the market. Although increasing the blend limit alone is not capable of meeting the RFS

[61] On November 30, 2009, the EPA notified Growth Energy that the waiver request decision would be delayed until mid-year 2010, pending results from DOE vehicle test programs. The letter can be viewed here: http://www.growthenergy.org/static/docs/2009/11/letter_EPAtoGrowthEnergy.pdf

requirements (without the need for E85), it does have the potential to provide valuable time needed to expand the E85 and FFV infrastructure [25].

The greatest impacts and concerns related to an increased blend limit fall in the retail and end use segments of the fuel supply chain. The E15 waiver request submitted in March 2009 saw immediate reactions from engine manufacturers, consumer advocacy groups, and various industry groups—ranging from the Alliance of Automobile Manufacturers to the Society of Independent Gasoline Marketers (SIGMA) and the National Association of Convenience Stores (NACS)—with concerns about potential damages to engines in vehicles and other gas-powered equipment, and the financial and legal implications facing the retail sector [212, 213].

As mentioned in the previous section, engine manufacturers do not warrant the use of blends exceeding E10 in conventional (non-flex-fuel) vehicles, coinciding with the limit imposed on motor gasoline by the CAA. Only FFVs are warranted to run on blends exceeding 10%. In responding to the waiver request, Charles Territo, spokesman for the Alliance of Automobile Manufacturers, argued that Growth Energy has failed to prove that E15 would not damage vehicles designed to run on E10. Wendy Clark, group manager and principal researcher in the fuels performance group at NREL, explained that it is simply too early to know how engines will be affected by E15 [212]. If the E15 waiver is granted by the EPA, it is unclear how engine warranty concerns would be resolved. Alan Adler, spokesperson for GM Corporation, explains that "we want to be sure that we're not on the hook for vehicles" that have problems with higher ethanol blends [213]. Cars and trucks are not the only concern. Hundreds of millions of small gasoline-powered engines in lawnmowers, weed trimmers, chainsaws, etc, and small to large engines in various watercrafts could be affected by the use of intermediate ethanol blends.

In anticipation of these concerns, the U.S. DOE initiated a test program in the summer of 2007 to evaluate the potential impacts of intermediate ethanol blends on legacy vehicles and other engines, including small non-road engines [168]. The objective of the DOE program, conducted by researchers at the ORNL, is to evaluate the effects of

E15 and E20 on tailpipe and evaporative emissions, catalyst and engine durability, vehicle drivability, engine operability, and vehicle and engine materials. Results to date have shown that vehicles exhibit a loss of fuel efficiency equivalent with energy content of the fuel, and that regulated tailpipe emissions were "largely unaffected" by ethanol content. No obvious material compatibility issues were noted during testing, although such effects were not specifically characterized during initial testing. A materials compatibility test program, to be conducted in collaboration with the Coordinating Research Council (CRC), will evaluate the durability of fuel-wetted components of fuel systems in non-FFVs when exposed to different intermediate ethanol blends, including impacts to plastics, elastomers, o-rings, and hose materials. When considering the current opposition from OEMs and consumer advocacy groups, the results of the test programs being funded and conducted by the DOE will be closely watched. To ensure the validity and support of this continuing program, the DOE plans to work closely with the EPA and various industry stakeholders to ensure that the test programs are conducted in a sound manner and targeted at providing the data needed to properly evaluate the effects of intermediate blends.

Similar concerns arise in the retail sector. Although fuel stations have been handling motor gasoline with ethanol up to 10%, questions remain as to whether existing equipment is compatible with intermediate blends. Many state and local fire codes require third party certification for fuel handling equipment, a task most often handled by Underwriters Laboratories (UL), an independent product safety certification organization. Existing fuel pumps, although safe with blends up to 15%, will not be approved for E15 by UL because E15 could actually represent a wider range of blends, including, e.g., E16. UL has stated that even if existing pumps could handle E15, the company cannot retroactively certify existing pumps. This problems leaves essentially two options for retailers: (1) sell fuel with incompatible equipment, or (2) replace existing equipment with approved, compatible equipment [214]. This problem applies not only to fuel pumps, but the entire range of fuel-wetted components in the fuel retail sector, e.g., storage tanks, fuel lines, dispenser nozzles, etc.

To allow for greater flexibility in selection of equipment that is compatible with various ethanol blends, UL recently announced a new certification path for fuel dispensers for mid-level blends up to E25 [215]. This new path provides manufacturers with three certification options, which, according to UL, allows manufacturers to "balance market needs and provide maximum flexibility as advances are made in the fuel industry." The three certification pathways cover gasoline and ethanol fuel blends up to E10, E85, and E25. Jeff Smidt, General Manager of Global Energy Business for UL, explains the reason for the third certification option as follows [215]:

> There is increased potential for different types of damage to materials and components at blends above E25 and, as a result, there are more stringent requirements for dispensers for use with these higher blend levels. This new mid-level option, up to E25, provides another certification path and can help facilitate the distribution of ethanol blends in the market.

Therefore, if the blend limit is increased, retailers will have an option to procure equipment that is certified for blends up to E25, rather than jumping to more expensive, and possibly unnecessary, E85-compatible equipment.

One approach being advocated by ethanol industry groups is the increased use of so-called "blender pumps" at retail stations [216]. Blender pumps are comprised of two underground tanks, one with unleaded gasoline (i.e., E0), and one with E85. The system blends and dispenses the appropriate percentage of each fuel to create a customer-specified blend level ranging from 0% to 85%. Advocates of blender pumps explain that such systems provide the consumer with new choices at the pump, and benefits station owners by providing flexibility should an increase in the blend limit be approved. Currently, the benefit of blender pumps is mostly restricted to consumers with FFVs, since blends above E10 are only warranted for use in FFVs. If the blend limit is increased, blender pumps will enable retailers to immediately supply the market with intermediate blends. In addition, blender pumps could be helpful in providing options to retailers and consumer alike, in the selection of an ethanol blend that minimizes cost as the price spread between ethanol and gasoline fluctuates. For example, if the price spread increases dramatically, e.g., ethanol price is 34% less than gasoline, then the consumer could choose to fuel up on a high blend, e.g., E85. If the spread is narrow, then the consumer could choose to limit the amount of ethanol they blend into the fuel. Some retailers, echoing the concerns of engine and vehicle manufacturers, contend that the new pumps could encourage non-FFV owners to fuel with intermediate blends because ethanol is cheaper than conventional gasoline. Due to UL resistance to recertify existing equipment, and liability concerns facing retailers that choose to dispense higher blends with existing equipment, expanded use of blender pumps could be limited [217]. Although blender pumps could provide flexibility to retail station owners, and more choices to consumers, the expenses associated with upgrading a station are likely to be analogous to the E85 costs presented in Table 4-8, since tank and dispenser conversions and/or replacements would be necessary.

The EPA, in a sensitivity analysis conducted in the RFS2 DRIA, considered the impacts of a waiver request being approved for E15 or E20 blends [25]. However, in their analysis, they assumed that legacy vehicles would continue to operate on E10, while Tier 2 vehicles[62] would be approved for blends up to E20. Therefore, the market would still have to provide E10, E15/20, and eventually E85. Since a portion of the market continues to be supplied with E10, the effects of increasing the blend limit are mitigated, e.g., the need for an E85 market is delayed less than if the entire supply of motor gasoline is blended to the increased blend limit. Ultimately, actions taken by OEMs will be crucial in determining whether the blend limit will be increased, and if it is increased, whether intermediate blends will be available to the entire fleet, or a limited segment (e.g., Tier 2 vehicles).

From a production standpoint, an increased blend limit is of little concern. Ethanol producers will continue to produce denatured ethanol to meet the conventional and cellulosic biofuel mandates. With regards to fuel specifications and formulations, oil refiners could potentially be impacted. With an increased percentage of ethanol, refiners

---

[62] Vehicles meeting the EPA Tier 2 requirements were first manufactured in the 2004 model year. See http://www.epa.gov/tier2/ for details.

could be required to alter the gasoline blendstock to ensure that a higher-blend motor gasoline, e.g., E15, still meets specifications required in different states and metropolitan regions.

In the distribution network, the impacts of an increased blend limit could be varied. Overall, the impacts would be limited to blending/distribution terminals and delivery to retailers. Upstream of blending terminals, the distribution system would continue to operate as usual; denatured ethanol and gasoline blendstock would continue to be delivered separately to blending terminals. If the blend limit is increased, and is approved for the entire existing fleet of vehicles, i.e. the approval is not limited to Tier 2 vehicles, then the distribution system would only be required to adapt to an increasing blend level in motor gasoline. At blending terminals, equipment that is currently used to handle and store motor gasoline (up to E10) could be found to be incompatible with intermediate blends, requiring equipment upgrades. Shipping containers used to transport blended fuels to retailers, i.e., truck trailers, could face similar issues. If the blend limit is increased, but the approval is limited to Tier 2 vehicles (and FFVs), then the market would have to supply multiple fuels: E10, E15/E20, and eventually E85. Blending terminals could be faced with blending, storing, and distributing the additional intermediate blend. This determination would be based on the acceptance and growth of blender pumps at retail stations. If blender pumps are not installed widely, distribution networks would shoulder the burden of blending, storing, and distributing the intermediate blend. Otherwise, standard motor gasoline (E10) and E85 would continue to be distributed to retailers, as they would have the capability to supply intermediate blends with blender pumps.[63] In summary, impacts to the distribution segment of the fuel supply chain are dependent upon OEM approvals and the acceptance of blender pumps in the retail segment. By reducing the extent of the E85 market, increasing the blend limit

[63] In section 1.7.1.3 of the EPA RFS2 DRIA, a retail configuration for dispending mid-level blends with existing retail infrastructure, as proposed by SIGMA/NACS, is presented. However, this configuration is still reliant on a distribution infrastructure capable of delivering motor gasoline (E10), an intermediate blend (E15/E20), and E85. The retail configuration allows retailers to avoid the need for blender pumps, while retaining the ability to offer regular, midgrade, and premium motor gasoline.

has the potential to limit the number of terminals that would be required to blend, store, and distribute E85.

In addition to delaying the need to develop E85 infrastructure, and limiting the size of the E85 market, increasing the blend limit has the potential to (1) provide some flexibility in meeting the RFS and (2) limit the impacts of future policy changes. By limited the overall size of the E85 market, an increased blend limit provides some flexibility in the design of ethanol markets. For example, regions with a high concentration of ethanol producers could more aggressively develop E85 markets, by providing incentives for consumers to purchase FFVs and retail station owners to install E85 equipment (or blender pumps). Outside of these E85 regions, intermediate blends could be integrated into existing infrastructure, limiting or negating the need for E85 markets.

By delaying the need for, and extent of, an E85 market, an increased blend limit could prevent significant capital investments in the fuel supply chain infrastructure from ending up as sunk costs, or stranded assets. For example, if advanced biofuel technologies develop in the coming years, allowing synthetic fuels to enter the market, the need for ethanol-compatible infrastructure would become unnecessary as ethanol is displaced, and rendered obsolete, by advanced biofuels.[64] The entire blend limit issue would become a non-issue if and when the fuels industry moves to advanced biofuels, which serve as "drop-in" replacements to crude-based gasoline. In addition, if the RFS mandate was to be suspended, or revised to require a more modest consumption of biofuels in the coming years, and thereby limiting or negating the need for E85, then sunk costs could, again, be avoided or minimized by delaying and limiting the extent of the E85 infrastructure.

Finally, it should be noted that the blend limit has no impact on the DFO sector, and thus does not affect the production, distribution, retail, and consumption of bio-based distillate.

[64] The increased production of bio-based synthetic fuels is discussed further in section 4.5.3.

4.5.3 Increased production of bio-based synthetic fuels

This section encompasses scenarios 3(a), 3(b), and 4, since all are based on the increased production of bio-based synthetic fuels (i.e., advanced biofuels), and limit the growth of the ethanol industry. As explained previously, advanced biofuels, which are compatible with existing infrastructure, have the potential to limit, or negate, the need for an ethanol-compatible infrastructure and the associated capital investments.[65]

Cellulosic diesel, or Fischer-Tropsch (FT) diesel, supplies half of the cellulosic biofuel mandate in scenario 3(a), while the entire cellulosic mandate is met with cellulosic diesel in scenario 3(b). Cellulosic diesel is a BTL fuel. The term BTL is applied to any synthetic fuel that is made from biomass through a thermo-chemical pathway [218]. Synthetic diesel can be produced from lignocellulosic feedstocks through gasification processes and the FT process. The FT process has been utilized to produce synthetic diesel with coal and natural gas feedstocks. Rather than following a fermentation pathway to produce cellulosic ethanol, synthetic diesel is produced by converting the lignocellulosic feedstocks first to synthesis gas, i.e., syngas, and then converting the syngas to liquid hydrocarbons via the FT process. The resulting hydrocarbons can be further refined through conventional petroleum refining processes, such as hydrocracking. Scenario 4 is analogous to 3(a), except that half of the cellulosic biofuel mandate is met with renewable gasoline. Like cellulosic diesel, renewable gasoline is produced with lignocellulosic feedstocks through a thermo-chemical pathway. Hydrocarbons produced from the FT process would require further upgrading with conventional petroleum refining processes.

Additional fuels are being developed that could contribute to this "compatibility" pathway. Renewable diesel is the term applied to hydrogenation-derived renewable diesel (HDRD), a high-quality, synthetic substitute to crude-based distillate. Renewable diesel is produced through the reaction of an oil-based feedstock (i.e., triglyceride) with excess hydrogen under high pressure and temperature to produce saturated hydrocarbons.

[65] The development and use of biofuels that are compatible with existing engines and infrastructure aligns well with the integrated view of vehicle and fuels, as discussed in section 2.4.4.

This process can be run in an independent facility, or in existing oil refineries, and can even be operated with a blend of triglycerides and petroleum. Gasoline can be produced using similar processes, but, according to the U.S. DOE, this process is in early stages of development. A number of companies are working to develop HDRD production processes, including ConocoPhillips, Neste Oil, Petrobras, Syntroleum, and UOP-Eni [10]. As mentioned previously, the availability of oil-feedstocks (e.g., vegetable oils, rendered animal fats, etc) for fuel production remains in question. The development of algae as a source of triglycerides could address this feedstock supply issue in the long term [219]. Algae are being researched as a potential feedstock for the production of a range of biofuels, including renewable diesel and gasoline, biocrude, and conventional biofuels, i.e., biodiesel and ethanol. A discussion on biobutanol, an alcohol fuel that can be derived from the same feedstocks as ethanol, is presented in section 4.4.4.2.

In essence, any combination of advanced biofuels that satisfy the requirements of the RFS mandate could be developed to displace the expanded production of ethanol, as illustrated through scenarios 3(a), 3(b), and 4. However, a primary hurdle to the commercial production and market penetration of these fuels is the development of advanced fuel production technologies. As discussed in chapter 1, the only liquid biofuels currently produced on a commercial scale are conventional starch ethanol and biodiesel. The technologies needed to produce BTL fuels (e.g., FT diesel, renewable gasoline), renewable diesel (HDRD), biobutanol, and even cellulosic ethanol, are still in research and development stages. In order to displace conventional biofuels, not only do advanced biofuels production technologies need to be proven on a commercial scale, but they must be capable of producing fuels that can compete on a cost basis with conventional biofuels, and conventional petroleum fuels.

The NRC panel, in a review of biochemical conversion pathways, acknowledges the importance of developing advanced biofuels from lignocellulosic feedstocks, and not limiting research and development to the production of ethanol [105]:

> Future improvements in cellulosic technology that entail invention of biocatalysts and biological processes could produce fuels that supplement ethanol production

> in the next 15 years. In addition to ethanol, advanced biofuels (such as lipids, higher alcohols, hydrocarbons, and other products that are easier to separate than ethanol) should be investigated because they could have higher energy content and would be less hydroscopic than ethanol and therefore could fit more smoothly into the current petroleum infrastructure than ethanol.

The panel recommends that the federal government should support research focused on technologies that could convert biomass feedstocks directly to advanced biofuels that can be seamlessly integrated into the existing infrastructure. However, the panel acknowledges the challenges facing the large-scale commercial application of these immature technologies, and stresses the need for continued federal and industry support of R&D and demonstration programs.

In their review of thermochemical pathways (e.g., to produce FT diesel), the panel is more optimistic about the state of technology, but stresses the importance of technology demonstration, which is needed to support commercial-scale production [105]:

> The advanced technologies for gasification, syngas cleanup, and Fischer-Tropsch synthesis have been demonstrated on a commercial scale. Their integration on the scale required to have a substantial impact on fuel production has not been demonstrated but is not considered a major issue.
>
> The technology for producing liquid transportation fuels from biomass...via thermochemical conversion has been demonstrated but requires additional development to be ready for commercial deployment.
>
> Key technologies should be demonstrated for biomass gasification on an intermediate scale…to obtain the engineering and operating data required to design commercial-scale synthesis gas-production units.

Based on the state of advanced biofuels production technologies, the ability of the industry to scale up production of these compatible biofuels to supply the increasing volumes mandated by the RFS program is questionable. Although the scenarios that present such a pathway may not be reasonable in terms of initial market penetration, the benefits gained from the eventual increased production of these fuels should not be overlooked. As discussed in section 4.5.1, the E10/E85 pathway to meeting the RFS will require substantial investments throughout the fuel supply chain infrastructure in order to distribute and consume a fuel that is incompatible with existing infrastructure. The capital investments made to support the increased production and distribution of ethanol, and increased fleet of FFVs to consume increasing volumes of E85, have the potential to end up as sunk costs if and when advanced biofuels technologies are scaled up. Advanced biofuels, which are compatible with existing infrastructure, could essentially render the ethanol (E85) infrastructure obsolete.

Setting aside the blend limit variable, these scenarios (3 and 4), when compared to the base case, present two potential pathways: (1) the nation limits the expansion of "first-generation" biofuels and the associated infrastructure investments until advanced biofuel technologies are developed and scaled up, thereby limiting the potential energy and environmental benefits associated with near-term biofuels consumption, or (2) push ahead with "first-generation", incompatible biofuels, i.e., ethanol, making substantial infrastructure investments that could potentially end up as sunk costs if and when advanced, "next-generation", compatible biofuels enter the market. This issue becomes a question of potential near-term energy and environmental benefits weighed against the costs to develop an infrastructure that would be rendered obsolete with the development of compatible biofuels in the future.

Although the benefits of synthetic fuels have been discussed throughout this section, some of the same distribution challenges facing conventional biofuels will need to be addressed. The production of synthetic fuels, being dependant on the same, or similar, feedstocks as conventional biofuels, will likely still occur in a large number of widely dispersed biorefineries. With an existing distribution system developed around the concentrated petroleum refining industry, the collection and distribution of this more dispersed supply of fuel remains a challenge. However, due to the removal of the "incompatibility hurdle," these fuels are capable of being seamlessly integrated into existing infrastructure, including pipelines. If the pipeline infrastructure is able to be utilized, a biofuels distribution system could be developed around the exiting petroleum distribution infrastructure. Fuels could be transported to the Gulf Coast through various transportation modes (e.g., barge), blended into finished products for various markets, and distributed via the existing pipeline infrastructure to destination terminals [193, 196].

An added benefit of synthetic fuels, aside from compatibility with infrastructure, is the higher energy content when compared to ethanol. As discussed in section 4.5.1, the lower energy content of ethanol has implications in the distribution, retail, and end use segments, requiring a greater volume of liquid fuel to be transported and consumed relative to the gasoline it displaces. With energy contents nearly equivalent to crude-based gasoline and diesel, the synthetic fuels would be transported, stored, dispensed, and consumed in volumes equivalent to conventional crude-based fuels.

4.5.4 Scenario 5: Variable liquid fuels demand

Whereas the previous scenarios present alternative pathways to meeting the RFS, scenarios 5(a) and 5(b) illustrate the impacts of variable liquid fuels demand in a transition to increased consumption of biofuels. Both are identical to the base case, except that total liquid fuels demand is altered—decreased in 5(a) and increased in 5(b). As discussed in section 4.4.5, liquid fuels demand could be influenced by a number of factors, ranging from changes in economic conditions to altered energy policies and trends in the liquid fuels sector (e.g., increased electrification of the LDV fleet). These scenarios illustrate the implications of the RFS program being designed as a volume mandate, in that regardless of overall demand, the mandated consumption of biofuels remains unchanged.

If the objective of a biofuels transition is to reduce petroleum consumption and GHG emissions from the transportation sector, then more rapid reductions can be realized when total liquid fuels demand is reduced in combination with mandated increases in biofuels consumption. Policies aimed at reducing total liquid fuels demand, in combination with the RFS, could force the sector through a more rapid transition. Although absolute production and consumption of biofuels remains unchanged, the relative share of biofuels in the liquid fuels sector would grow more rapidly.

From a production perspective, the impacts would be no different than the base case. The mandate still requires 36 bgy of biofuels by 2022, so the same increase in conventional and cellulosic ethanol facilities would be needed, along with the modest increase in bio-based distillate production. The distribution and retail infrastructure, built around petroleum products, would be faced with a more rapid penetration of E85. In order to consume the increased volume of E85, a greater percentage of the nation would require "reasonable access" to the fuel, requiring more blending terminals and retailers to be capable of handling and dispensing the fuel. Although these segments of the supply chain would face challenges with this more rapid transition, the reduced total demand presents some benefits. For example, as total liquid fuels demand falls, more of the existing storage capacity could be used to store denatured ethanol and various blends, rather than forcing terminals to expand storage capacity. With a rapidly growing E85 market, retailers would be presented with a more robust market, better justifying investments in E85 compatible equipment. In the end use segment, fleet turnover poses a significant challenge. As demand falls, and ethanol is increasingly supplied as E85, the population of FFVs would be required to grow more rapidly. However, if total liquid fuels demand declines as a result of reduced average VMT, the rate of fleet turnover could be reduced: as consumers drive less, their vehicles could remain in use for extended periods of time, slowing fleet turnover and the introduction of FFVs.

If total liquid fuels demand increases, relative to the base case, the situation is relatively unchanged. Many of the barriers and hurdles facing the liquid fuels sector are identical, or could potentially be mitigated due to the overall growth in the sector. With increased total demand, the rate of growth and size of the E85 market are reduced, requiring a smaller portion of the nation to have "reasonable access" to the fuel. Less terminals and retailers would be required to make the necessary upgrades to handle and dispense the new fuel. With a smaller E85 market, some retailers and terminals could find it more difficult to justify the investments needed to upgrade equipment. With less E85 needing to be consumed, fewer FFVs would be needed in the fleet, mitigating concerns related to fleet turnover. However, as total demand increases, the sector will be faced with increases in total capacity. When considering the fact that many parts of the liquid fuels distribution system already face capacity constraints [193, 196, 220], the additional strain of adding capacity to handle biofuels, i.e., ethanol, could be an added burden. Due to the lower energy content of ethanol relative to crude-based gasoline, an increased supply of ethanol would force greater capacity expansions compared to an energy-equivalent increase in crude-based gasoline.

4.5.5 Uncertainty

These scenarios raise an additional concern that is common to any biofuels transition pathway—uncertainty.[66]

The pace and success of technology development and advancements are a major source of uncertainty in a biofuels transition. In all scenarios, conventional biofuels are capped at 15 bgy starting in 2015. The continued expansion of the biofuels industry is then reliant on advanced biofuels production technologies (and continued expansion of new biofuel feedstock supplies). This uncertainty in fuel supply impacts investment decisions not only in production facilities, but in all segments downstream in the supply chain. Uncertainty in the biofuels supply could serve as an incentive for stakeholders in the distribution and retail industry to withhold or delay necessary infrastructure investments. Vehicle manufacturers could be faced with consumers unwilling to shoulder the added costs associated with FFVs if the ethanol supply does not expand sufficiently to justify an E85 or other high-blend market. The investments required to support an E85 market are also put into question by the potential development of advanced, compatible biofuels technologies, which could cause such infrastructure investments to end up as stranded assets.

The sheer magnitude of major infrastructure investments also stands as a source of uncertainty. Estimating the costs of large scale projects is often a major challenge, e.g., nuclear power plants, new technology demonstration projects, etc, often face major cost overruns compared to initial cost estimates. Finally, continuity of energy policy is

[66] This thesis does not include a formal uncertainty analysis of the transition scenario results.

another source of uncertainty [92, 193, 221]. Policy certainty is needed to justify the long-term, large-scale investments required in a biofuels transition. If policies are continuously altered, e.g., if the EPA freely grants state waivers to the RFS program, then stakeholders will be hesitant, or unwilling to make the necessary investments to ensure a smooth transition.

The NCEP explains that "uncertainty therefore emerges as a key crosscutting barrier to the infrastructure investments that will be needed to allow for a smooth transition." In order to reduce uncertainty and promote a stable market, the NCEP proposes the following policy measures as means for supporting the RFS mandate [193]:

- continuity of the RFS program;
- deployment of FFV and fuel distribution infrastructure (e.g., promoting FFVs on a timetable that coincides with mandated volumes);
- improve permitting processes throughout the supply chain;
- simplify and/or harmonize fuel specifications (e.g., eliminate state-level specifications);
- allocate federal resources for critical infrastructure investments (e.g., retail equipment).

These recommendations align well with the challenges facing the base case scenario, which satisfies the requirements of the RFS through and E10/E85 future. However, several of these measures are applicable to all scenarios, or could be adapted and extended to pathways less reliant on an expanded ethanol industry.

4.6 Conclusions

The Renewable Fuels Standard (RFS) program has played a crucial role in the recent growth of the biofuels sector, and stands as a key driver in a transition to biofuels in the near term. By mandating annual consumption of biofuels, increasing to 36 billion gallons per year (bgy) in 2022, the program has the potential to significantly alter the state of the U.S. liquid fuels sector. As the RFS program mandates greater volumes of biofuels, there is substantial uncertainty facing the liquid fuels sector as to how such a transition will unfold.

A set of projections, or scenarios, of the liquid fuels sector was developed using a model of the sector—the Liquid Fuels Transition (LiFTrans) model. The scenarios illustrate different pathways to meeting the requirements of the RFS mandate, with total biofuels production that is no more or less than the mandated volumes. These scenarios differ based on the overall demand of liquid fuels, how the biofuels mandate is met (i.e., the mix of biofuels), and the status of the ethanol blend limit in the motor gasoline sector. The scenarios were used to evaluate the infrastructure implications associated with a biofuels transition, and illustrate the uncertainty that exists in assessing such a transition.

The scenarios represent three basic pathways to meeting the RFS mandate: (1) increase the availability of E85 in the market in conjunction with increased production of FFVs; (2) lessen the "incompatibility hurdle" through the production of synthetic fuels, or more compatible fuels; or (3) increase the ethanol blend limit. In addition, the impact of variable total liquid fuels demand was illustrated (with scenario 5). As a volume-based mandate, the RFS program requires an annually increasing volume of biofuels to be consumed, regardless of changes in total demand.

Any pathway to a biofuels transitions will require simultaneous technological and operational changes throughout the fuel supply chain, which includes feedstock production, fuel production, distribution, retail, and end use. The extent of these impacts is influenced by the nature of the biofuels (e.g., chemical/physical properties, state of production technology, etc) produced to meet the mandate. Like the historical fuel transitions in chapter 2, different fuels force different changes throughout the fuel supply chain. In summary, each scenario, or alternative pathway to meeting the RFS mandate, has a set of tradeoffs facing the liquid fuels sector in a transition to biofuels. Each scenario presents a range of challenges, or barriers, which must be addressed to ensure a successful transition. While one scenario could potentially mitigate challenges associated with another scenario, most often other challenges arise. The production of bio-based synthetic fuels to displace ethanol production exemplifies these tradeoffs. By overcoming the "incompatibility hurdle," synthetic fuels can limit or negate the significant infrastructure investments required to distribute increasing volumes of E85. However, the technologies needed to produce, and the infrastructure needed to collect, synthetic fuels have yet to be deployed on a commercial scale. While these advanced biofuels could limit capital investments that end up as stranded assets, the time needed to develop the necessary production technologies could delay and prolong a biofuels transition.

A limitation of this analysis is the omission of barriers related to biofuel feedstocks, including the growth, harvesting, collection, storage, and logistics associated with feedstock supply. The need to identify and develop markets for biofuel co-products[67] is another major challenge. For example, increased biodiesel production has increased the supply of glycerin, a co-product of the transesterification process. Developing robust markets for this chemical has become a major challenge for some producers, exemplified by recent incidents of biodiesel producers illegally dumping excess glycerin into waterways [222]. As arable land is increasingly converted to the production of biofuel feedstocks, the contribution of emissions from indirect land use changes to overall lifecycle GHG emissions could prevent some biofuels (i.e., feedstocks) from qualifying under the biofuels mandate [25, 26, 223, 224]. Although this analysis is limited to barriers downstream of feedstock production, the importance of feedstocks should not be downplayed. Without a sustainable and sufficient supply of feedstocks, the barriers that arise throughout the remainder of the biofuels supply chain become irrelevant. However, to ensure a manageable scope, this portion of the supply chain was excluded from the analysis.

This discussion has served to identify a number of issues that must be addressed during a biofuels transition. With these issues identified, this analysis could be extended to quantify the true costs and benefits of each scenario and the tradeoffs that they present.

[67] A co-product is any additional product (aside from the fuel) that comes from a unit process in the biofuel production process. For example, soy biodiesel production creates two co-products: soy meal from the oil extraction process, and glycerin from the transesterification process.

Chapter 5. Conclusions

Demand for liquid fuels (i.e., petroleum products) has burdened the U.S. with major challenges, including national security and economic concerns stemming from rising petroleum imports; impacts of global climate change from rising emissions of CO2 emissions; and continued public health concerns from criteria and hazardous (i.e., toxic) air pollutants. Over the last decade or so, biofuels have been touted as a supply-side solution to several of these problems. Biofuels can be produced from domestic biomass feedstocks (e.g., corn, soybeans), they have the potential to reduce GHG emissions when compared to petroleum products on a lifecycle basis, and some biofuels have been shown to reduce criteria air pollutants. Today, there are numerous policy incentives—existing and proposed—aimed at supporting the biofuels industry in the U.S. However, the EPA-administered Renewable Fuel Standard (RFS) Program stands as perhaps the most significant mandate imposed to date to promote the use of biofuels. Overall, the RFS stands as the key driver in a transition to biofuels in the near term. By mandating annual consumption of biofuels, increasing to 36 bgy by 2022, the program has the potential to significantly alter the state of the liquid fuels sector.

Fuel transitions in the transportation sector are the focus of this thesis. More specifically, the increasing consumption of biofuels in the transportation sector, as mandated by the RFS, is examined. This mandated biofuels transition will undoubtedly require substantial investments in a relatively short period of time in order to develop, or modify, the necessary infrastructure, fuel and vehicle technologies, and other elements that link together to deliver transportation services (e.g., regulations, industrial networks). With a well-developed, efficient, and expensive, petroleum-based infrastructure in place, many barriers must be overcome for biofuels to play a significant role in the transportation sector. Identifying and understanding the barriers to a biofuels transition is the objective of this thesis.

Although fuel transitions may seem daunting and unfamiliar, the U.S. transportation sector has undergone numerous transitions in the past. Many pertinent lessons can be derived from these historical transitions and used to identify and assess barriers facing the adoption of alternative fuels (i.e., biofuels) and to understand how such a transition might unfold. Chapter 2 reviewed major fuel transitions that have occurred in the U.S. liquid fuels sector over the last half century. Transitions in the motor gasoline sector include the phasing out of lead additives in gasoline, the use of high octane hydrocarbons to recover octane in gasoline, the mandated use of oxygenate additives in gasoline, the transition from MTBE to ethanol as the predominant oxygenate additive in gasoline, and the ongoing growth of ethanol as a direct substitute for crude-based gasoline. The DFO sector has undergone two reductions in sulfur content in diesel fuel since the early 1990s: the introduction of LSD, and the transition to ULSD. These historical transitions represent the uncertainty and diversity of fuel transition pathways, and illustrate the range of impacts that can occur across the fuel supply chain infrastructure. The liquid fuels sector is comprised of a massive, well-established network of industries and accompanying infrastructures, supported by and integrated with regulations, practices, and institutions. A transition to biofuels in the liquid fuels sector will not occur independently or in isolation from this system. Understanding how previous transitions progressed and altered this established sector is critical to the analysis of future transitions.

This review of historical transitions has shown that fuel transitions are a common occurrence in the liquid fuels sector. The time scales, or durations, of these transitions have been quite variable, ranging from approximately one year (e.g., introduction of LSD), to nearly 20 years (e.g., unleaded gasoline). The rate at which a fuel enters the market is influenced by how the properties and performance of the fuel change, since a significant change in the nature of the fuel can produce more far-reaching implications throughout the fuel supply chain. If a fuel transition requires additional fuels to be handled, rather than replacing an existing fuel, more challenges can arise, particularly in the distribution and retail segments, slowing the transition. The state of technology is another important factor influencing the duration of transitions. Fuels that require the development and application of immature technologies will be slow to enter the market.

Attempting to determine the rate at which a biofuels transition will occur is no simple task. It will be influenced by a number of factors, related to the properties of biofuels introduced into the market, the ability of these fuels to be handled with existing fuels throughout the infrastructure, and the state of technologies needed to produce and consume the fuels. Ethanol, the most common biofuel currently consumed in the liquid fuels sector, has properties that differ significantly from gasoline; it is handled separately throughout the distribution infrastructure; and its increased production will rely on the development of new technologies (e.g., cellulosic ethanol production technologies) and feedstocks, and the continued expansion of production capacity. As ethanol production expands to meet the RFS mandate, eventually exceeding the motor gasoline blend limit (10%), ethanol must be increasingly blended as E85. When viewed in the context of the historical transitions, these factors point to a relatively slow transition, potentially exceeding the range of fuel transitions reviewed in chapter 2, i.e., several decades.

Historical fuel transitions also highlight the utility of viewing vehicles and fuels as a single technological system. Fuels that can be used in the existing fleet of vehicles (and infrastructure) can be more easily integrated into the fuel supply, increasing the rate of market penetration, and decreasing economic costs. If a proposed alternative fuel, or fuel formulation, has the potential to negatively impact vehicle performance, or increase operating costs, it should be carefully scrutinized. With a well-developed, efficient, and expensive, petroleum-based infrastructure in place, introducing fuels that are incompatible could face more significant challenges than those fuels that differ little from existing conventional fuels. The example of biodiesel and bio-based synthetic distillate fuels served as an example of this principle being applied to the use of biofuels in the DFO sector.

System boundaries were shown to be an important factor in the analysis of historical fuel transitions. When assessing the potential impacts of a fuel transition, if the boundaries of the assessment, or analysis, are not chosen appropriately, important impacts can be neglected. Historically, such oversights have lead to the repeated occurrence of unintended consequences. When new fuel technologies and/or regulations (e.g. the RFS program) are being developed, and impacts are assessed, approaching this analysis with a lifecycle perspective can help to limit the occurrence and severity of unintended consequences: the potential for shifting problems, whether through energy, economic, societal, or environmental costs, can be limited. In a biofuels transition, if an environmental assessment is limited to GHG emissions, negative outcomes—unintended or otherwise—have the potential to develop. The potential for increased water consumption and contamination stemming from the production of conventional ethanol serves as an example.

Fuel transitions have the potential to impact not only technologies, but other components of the sociotechnical configuration in transportation. Getting the technologies right is not always enough; societal, regulatory, economic, and cultural factors can act as barriers as well. The misfueling problem during the lead transition in the motor gasoline sector serves as an example of a cultural barrier. Consumers fueled their catalytic-converter-equipped vehicles with leaded gasoline because they were unaccustomed with the new, unleaded fuel, and had misconceptions and concerns about its impacts on vehicle performance and reliability. Despite the fact that the technology was in place, and operational changes were implemented (e.g., different size fuel dispenser nozzles and filler caps), consumers' familiarity with leaded gasoline had to be overcome. A biofuels transition has the potential to impact many of these non-technology factors; identifying and addressing these potential barriers is just as important as overcoming challenges related to technologies. For example, as ethanol production has expanded, and ethanol has been increasingly incorporated into the gasoline supply nationwide, some consumers have started to push back, demanding gasoline that is free of ethanol [115].

Determining the economic impacts, or costs, associated with historical fuel transitions was found to be challenging. Fuel transitions do not occur in isolation from other events driving investments in the liquid fuels sector. For example, investments made by the refining industry during the 1980s were not solely related to the lead transition, but were driven by changes in product demand, crude oil supply, and other environmental regulations. Just as the technological and operational impacts of a fuel transition are spread across various segments of the fuel supply chain, costs are distributed amongst a range of stakeholders. Similarly, a biofuels transition will not occur in a vacuum. Other policies and trends in the liquid fuels sector will drive additional investments, unrelated to biofuels, e.g., fuel efficiency standards will force vehicle manufacturers to invest in new technologies and alter production strategies. Like historical fuel transitions, a biofuels transition will require investments from a range of stakeholders throughout the fuel supply chain.

The limitations of this analysis must also be acknowledged. As discussed previously, fuel transitions in a given sector caused incremental changes of the same technology and base fuels, i.e., there are no examples of interfuel substitution. Although this review highlighted two examples of petroleum feedstocks being partially displaced during fuel transitions (e.g., natural gas in the production of MTBE, corn in the production of ethanol), no major displacement of crude oil with alternative feedstocks has occurred. A biofuels transitions is unique in this regard, and these historical transitions provide little context for understanding the implications of a true interfuel substitution. When considering the simultaneously technological and operational changes that will be required throughout the fuel supply chain, a biofuels transition will be unprecedented in scope.

Computer models can also serve to explore the implications of fuel transitions. In order to better understand the barriers associated with fuel transitions, and to identify options for overcoming these barriers, many recent research efforts have used sophisticated modeling techniques to analyze energy transitions. Chapter 3 reviewed a number of these recent modeling efforts with a focus on understanding how these methodologies have been applied, or may be adapted, to analyzing a transition to biofuels. Four general categories of models were reviewed: system dynamics, complex adaptive systems, infrastructure optimization, and economic models. Although many of the models reviewed in chapter 3 were developed for hydrogen, the methodologies are clearly pertinent to modeling a transition to biofuels as well. These models can be used to investigate a range of economic-, policy-, and technology-relevant issues facing a transition to biofuels. Models incorporate a range of features, such as the ability to test the potential impacts of government policies; track the economic costs and time scales associated with the development of new infrastructure; and calculate energy and environmental metrics.

The complex nature of the liquid fuels sector, which incorporates technological, social, economic, and environmental factors, presents modelers with unique challenges. Attempts at forecasting, or predicting transitions, are ultimately doomed to fail. However, the objective of transition modeling does not have to be scoped in this manner. The value of modeling efforts lies not in their ability to forecast, or predict specific transition events, but in their ability to reveal interdependencies, uncover potential barriers, and identify critical variables. By viewing transition models as tools for exploring potential pathways to alternative fuel futures, the pitfall of prediction and forecasting can be avoided. The greatest value of these modeling efforts may lie in the rigor and methods employed in the modeling process, which can help to uncover and develop new knowledge of complex system interactions, feedback loops, and other evasive parameters.

Some suggested applications and areas for further research were highlighted. For example, infrastructure optimization models could be developed to explore the development of fuel production and distribution infrastructure around regionalized biofuel feedstock supplies and end use markets. With different assumptions related to feedstock supply (e.g., availability, and geographic and seasonal distribution), growth in fuel demand, etc, alternative spatial and temporal designs of the infrastructure could be assessed.

Based on this review, it is evident that no single model can provide all the answers facing a biofuels transition; and for that matter, no combination of models can provide all the answers. It is recommended that an appropriate modeling methodology can only be selected after a well-defined research question (or set of questions) has been formulated. For instance, the infrastructure optimization models may not be particularly useful when attempting to understand the barriers to simultaneous penetration of FFVs and E85 fueling infrastructure. The identification of barriers to a biofuels transition, and strategies or means for overcoming and mitigated these challenges can be explored through the use of fuel transition models. However, much work remains to be done to improve the capabilities of this rapidly advancing field.

Finally, in chapter 4, a set of scenarios was developed to explore potential pathways and barriers to a biofuels transition. These scenarios were created from a high-level model of the liquid fuels sector, called the Liquid Fuels Transition (LiFTrans) model. The scenarios illustrate different pathways to meeting the requirements of the RFS mandate, with total biofuels production that is no more or less than the mandated volumes, and differ based on the overall demand of liquid fuels, how the biofuels mandate is met (i.e., the mix of biofuels), and the status of the ethanol blend limit in the motor gasoline sector. The scenarios were used to evaluate the infrastructure implications associated with a biofuels transition, and illustrate the uncertainty that exists in assessing such a transition.

The scenarios represent three basic pathways to meeting the RFS mandate: (1) increase the availability of E85 in the market in conjunction with increased production of FFVs; (2) lessen the "incompatibility hurdle" through the production of synthetic fuels, or more compatible fuels; or (3) increase the ethanol blend limit. In addition, the impact of variable total liquid fuels demand was illustrated (with scenario 5). As a volume-based mandate, the RFS program requires an annually increasing volume of biofuels to be consumed, regardless of changes in total demand.

Any pathway to a biofuels transitions will require simultaneous technological and operational changes throughout the fuel supply chain, which includes feedstock production, fuel production, distribution, retail, and end use. The extent of these impacts is influenced by the nature of the biofuels (e.g., chemical/physical properties, state of production technology, etc) produced to meet the mandate. Like the historical fuel transitions in chapter 2, different fuels force different changes throughout the fuel supply chain. In summary, each scenario, or alternative pathway to meeting the RFS mandate, has a set of tradeoffs facing the liquid fuels sector in a transition to biofuels. Each scenario presents a range of challenges, or barriers, which must be addressed to ensure a successful transition. While one scenario could potentially mitigate challenges associated with another scenario, most often other challenges arise. The production of bio-based synthetic fuels to displace ethanol production exemplifies these tradeoffs. By overcoming the "incompatibility hurdle," synthetic fuels can limit or negate the significant infrastructure investments required to distribute increasing volumes of E85. However, the technologies needed to produce, and the infrastructure needed to collect, synthetic fuels have yet to be deployed on a commercial scale. While these advanced biofuels could limit capital investments that end up as stranded assets, the time needed to develop the necessary production technologies could delay and prolong a biofuels transition.

A limitation of this analysis is the omission of barriers related to biofuel feedstocks, including the growth, harvesting, collection, storage, and logistics associated with feedstock supply. The need to identify and develop markets for biofuel co-products is another major challenge. For example, increased biodiesel production has increased the supply of glycerin, a co-product of the transesterification process. Developing robust markets for this chemical has become a major challenge for some producers, exemplified by recent incidents of biodiesel producers illegally dumping excess glycerin into waterways [222]. As arable land is increasingly converted to the production of biofuel feedstocks, the contribution of emissions from indirect land use changes to overall lifecycle GHG emissions could prevent some biofuels (i.e., feedstocks) from qualifying under the biofuels mandate [25, 26, 223, 224]. Although this analysis is limited to barriers downstream of feedstock production, the importance of feedstocks should not be downplayed. Without a sustainable and sufficient supply of feedstocks, the barriers that arise throughout the remainder of the biofuels supply chain become irrelevant. However, to ensure a manageable scope, this portion of the supply chain was excluded from the analysis.

This discussion has served to identify a number of issues that must be addressed during a biofuels transition. With these issues identified, this analysis could be extended to quantify the true costs and benefits of each scenario and the tradeoffs that they present.

Through a more quantitative analysis of biofuel transition scenarios, rate limiting factors could be identified. For example, the market penetration of a given biofuel could be limited by the growth of biofuel feedstock supplies, the pace of fuel production technology development and capacity expansion, congestion in the fuel distribution network, or the rate of fleet turnover (due to the need for new vehicle technologies). Based on these limiting factors, an optimal pathway could be identified based on various criteria, e.g., transition duration, economic costs, etc. With the tradeoffs of transition scenarios quantified, targeted strategies and policies could be formulated in a more deliberate manner. In addition, the feasibility of transition rates (e.g., facility build rates, fleet turnover requirements, etc) could be assessed, e.g., by comparing to historical fuel transitions.

In developing the scenarios presented in chapter 4, it was assumed that all biofuels meet the requirements of the RFS mandate, including the lifecycle GHG emission reduction thresholds. In reality, some biofuels may face barriers to market entry if they fail to meet these thresholds. Although this thesis has sought to identify technology-, economic-, and infrastructure-related barriers to a biofuels transition, the energy and environmental impacts of biofuels production and consumption cannot be ignored. By integrating the analysis presented in this thesis with biofuel lifecycle analysis (LCA) (e.g., lifecycle GHG emissions, criteria air pollutants, water consumption and quality impacts, land use change, energy return on energy invested), a more holistic view of the costs and benefits of a biofuels transition could be developed. If significant environmental or energy costs arise from the production and consumption of biofuels, then the analysis presented in this thesis is essentially rendered obsolete.

References

1. Energy Information Administration, *Annual Energy Review 2008, Table 1.3 Primary Energy Consumption by Source, 1949-2008*. 2009, U.S. Department of Energy, Energy Information Administration: Washington, D.C.
2. Energy Information Administration, *Annual Energy Outlook 2009, Table 11. Liquid Fuels Supply and Disposition*. 2009, U.S. Department of Energy, Energy Information Administration: Washington, D.C.
3. Energy Information Administration, *Annual Energy Review 2008, Table 5.11 Petroleum Products Supplied by Type, 1949-2008*. 2009, U.S. Department of Energy, Energy Information Administration: Washington, D.C.
4. Energy Information Administration, *Annual Energy Review 2008, Table 5.13c Estimated Petroleum Consumption: Transportation Sector, 1949-2008*. 2009, U.S. Department of Energy, Energy Information Administration: Washington, D.C.
5. Energy Information Administration, *Annual Energy Review 2008, Table 2.1e Transportation Sector Energy Consumption, 1949-2008*. 2009, U.S. Department of Energy, Energy Information Administration: Washington, D.C.
6. Energy Information Administration, *Annual Energy Review 2008, Table 5.1 Petroleum Overview, 1949-2008*. 2009, U.S. Department of Energy, Energy Information Administration: Washington, D.C.
7. Energy Information Administration, *Annual Energy Review 2008, Table 12.3 Carbon Dioxide Emissions From Energy Consumption by Sector by Energy Source, 2007*. 2009, U.S. Department of Energy, Energy Information Administration: Washington, D.C.
8. McCormick, R.L., et al., *Effects of Biodiesel Blends on Vehicle Emissions: Fiscal Year 2006 Annual Operating Plan Milestone 10.4*. 2006, National Renewable Energy Lab: Golden, Colorado. p. 69.
9. USDOE. *Alternative Fuels & Advanced Vehicles Data Center*. November 20, 2007 [cited February 1, 2008]; Available from: http://www.eere.energy.gov/afdc/.
10. US DOE. *Alternative Fuels & Advanced Vehicles Data Center*. 2009 July 31, 2009 [cited 2008 November 19]; Available from: http://www.eere.energy.gov/afdc/.
11. *biobutanol*. 2006 [cited February 8, 2008]; Available from: http://www2.dupont.com/Biofuels/en_US/index.html.

12. ConocoPhillips Company. *Emerging Technologies*. 2009 [cited 2009 August 26]; Available from: http://www.conocophillips.com/EN/tech/emerging/Pages/index.aspx.

13. Energy Information Administration. *Ethanol Timeline*. 2008 June 2008 [cited 2009 August 26]; Available from: http://www.eia.doe.gov/kids/history/timelines/ethanol.html.

14. US EPA. *Renewable Fuel Standard Program*. 2009 November 6, 2009 [cited November 18, 2009]; Available from: http://www.epa.gov/otaq/renewablefuels/.

15. Energy Information Administration, *Annual Energy Review 2008, Renewable Energy, Table 10.3. Fuel Ethanol Overview, 1981-2008*. 2009, U.S. Department of Energy, Energy Information Administration: Washington, D.C.

16. Renewable Fuels Association. *Biorefinery Locations*. 2009 August 4, 2009 [cited 2009 August 24]; Available from: http://www.ethanolrfa.org/industry/locations/.

17. National Biodiesel Board. *Biodiesel: The Official Site of the National Biodiesel Board*. 2008 [cited February 1, 2008]; Available from: http://biodiesel.org/.

18. Energy Information Administration, *Annual Energy Review 2008, Renewable Energy, Table 10.4. Biodiesel Overview, 2001-2008*. 2009, U.S. Department of Energy, Energy Information Administration: Washington, D.C.

19. National Renewable Energy Laboratory. *TransAtlas*. 2009 [cited 2009 August 24]; Available from: http://rpm.nrel.gov/transatlas/launch/.

20. Renewable Fuels Association. *Renewable Fuels Association*. 2008 [cited February 1, 2008]; Available from: http://www.ethanolrfa.org/.

21. US DOE. *State & Federal Incentives & Laws, Alternative Fuels & Advanced Vehicles Data Center,*. 2009 July 10, 2009 [cited 2009 August 24]; Available from: http://www.afdc.energy.gov/afdc/incentives_laws.html.

22. Yacobucci, B.D., *Biofuels Incentives: A Summary of Federal Programs*. 2007, Congressional Research Service.

23. *Energy Security for the 21st Century*. 2008 [cited February 8, 2008]; Available from: http://www.whitehouse.gov/infocus/energy/.

24. 110th Congress, *Energy Independence and Security Act of 2007, H.R. 6*. 2007: Washington, D.C.

25. US EPA, *Draft Regulatory Impact Analysis: Changes to Renewable Fuel Standard Program*, Assessment and Standards Division, Office of Transportation and Air Quality, Editor. 2009: Washington, D.C.

26. California Air Resources Board. *Low Carbon Fuel Standard Program*. 2009 October 15, 2009 [cited 2009 October 23, 2009]; Available from: http://www.arb.ca.gov/fuels/lcfs/lcfs.htm.

27. Secretary of the Air Force, *Air Force Energy Program Policy Memorandum*. 2009, U.S. Air Force: Washington, D.C.

28. Geels, F.W., *Technological transitions as evolutionary reconfiguration processes: a multi-level perspective and a case-study.* Research Policy, 2002. **31**(8-9): p. 1257-1274.

29. Sperling, D. and J. Dill, *Unleaded Gasoline in the United States: A Successful Model of System Innovation.* Transportation Research Record, 1988. **1175**: p. 45-52.

30. Seyferth, D., *The Rise and Fall of Tetraethyllead. 2.* Organometallics, 2003. **22**(25): p. 5154-5178.

31. Heywood, J.B., *Internal Combustion Engine Fundamentals*. McGraw-Hill Series in Mechanical Engineering. 1988: McGraw-Hill Book Company.

32. US EPA, *Costs and Benefits of Reducing Lead in Gasoline: Final Regulatory Impact Analysis*, EPA Office of Policy Analysis, Editor. 1985: Washington, D.C.

33. Kerr, S. and R.G. Newell, *Policy-Induced Technology Adoption: Evidence from the U.S. Lead Phasedown.* Journal of Industrial Economics, 2003. **51**(3): p. 317-343.

34. Newell, R.G. and K. Rogers, *The Market-based Lead Phasedown*. 2003, Resources for the Future: Washington, D.C.

35. US EPA. *EPA Takes Final Step in Phaseout of Leaded Gasoline*. September 21, 2007 [cited 2008 April 28, 2008]; Available from: http://www.epa.gov/history/topics/lead/02.htm.

36. Nichols, A.L., *Lead in Gasoline*, in *Economic Analyses at EPA: Assessing Regulatory Impact*, R.D. Morgenstern, Editor. 1997, Resources for the Future: Washington, D.C. p. 49-86.

37. Borenstein, S., *Price Incentives for Fuel Switching: Did Price Differences Slow the Phase-Out of Leaded Gasoline?*, in *Program on Workable Energy Regulation (POWER)*. 1993, University of California Energy Institute: Berkeley, CA.

38. Hammar, H. and A. Lofgren, *Leaded Gasoline in Europe: Differences in Timing and Taxes*, in *Choosing Environmental Policy: Comparing Instruments and Outcomes in the United States and Europe*, W. Harrington, R.D. Morgenstern, and T. Sterner, Editors. 2004, Resources for the Future: Washington, D.C.

39. US EIA (Energy Information Administration), *Annual Energy Review (AER)*. 2007: Washington, D.C.

40. US EIA (Energy Information Administration), *The U.S. Petroleum Refining Industry in the 1980s*. 1990, EIA: Washington, DC.

41. Energy Information Administration, *Short-Term Energy Outlook, Quarterly supply and disposition of motor gasoline*. 1983-1990, U.S. Department of Energy: Washington, D.C.

42. Energy Information Administration. *U.S. Product Supplied for Crude Oil and Petroleum Products*. 2009 May 28, 2009 [cited 2009 June]; Available from: http://tonto.eia.doe.gov/dnav/pet/pet_cons_psup_dc_nus_mbbl_m.htm.

43. Guibet, J.-C., *Fuels and engines: technology, energy, environment*. Rev. ed. ed. 1999, Paris: Editions TECHNIP. 2 v. (xxxvi, xli, 786 p.).

44. *The unleaded-gasoline tab: $4.2 billion*. The Oil and Gas Journal, 1967. **65**: p. 74-75.

45. Committee on Ozone-Forming Potential of Reformulated Gasoline, National Research Council, *Ozone-forming potential of reformulated gasoline*. 1999, Washington, D.C.: National Academy Press. xvi, 252 p. :.

46. Gibbs, L.M. *How gasoline has changed II - The impact of air pollution regulations*. in *SAE International Fall Fuels and Lubricants Meeting and Exhibition*. 1996. San Antonio, Texas, USA: SAE International.

47. U.S. Environmental Protection Agency. *Guide to Federal and State Summer RVP Standards for Conventional Gas Only*. October 20, 2008 [cited 2009 March 12]; Available from: http://www.epa.gov/otaq/volatility.htm.

48. Dickson, C.L., et al., *Motor Gasoline Survey Reports*. 1970-2008, Northrop Grumman.

49. Energy Information Administration. *U.S. Oxygenate Production*. 2009 January 30, 2009 [cited 2009 February 20]; Available from: http://tonto.eia.doe.gov/dnav/pet/pet_pnp_oxy_dc_nus_mbbl_m.htm.

50. Energy Information Administration. *U.S. Imports of Crude Oil and Petroleum Products*. 2009 June 29, 2009 [cited 2009 July]; Available from: http://tonto.eia.doe.gov/dnav/pet/pet_move_imp_dc_nus-z00_mbblpd_a.htm.

51. Energy Information Administration. *U.S. Exports of Crude Oil and Petroleum Products*. 2009 June 29, 2009 [cited 2009 July]; Available from: http://tonto.eia.doe.gov/dnav/pet/pet_move_exp_dc_nus-z00_mbblpd_a.htm.

52. Davis, S. and S.W. Diegel, *Transportation Energy Data Book, Table 2.10. U.S. Production and Imports of MTBE and Fuel Ethanol, 1985-2003*. 2004, U.S. Department of Energy: Oak Ridge, Tennessee.

53. US EPA. *Gasoline Fuels*. 2008 March 18, 2008 [cited July 2009]; Available from: http://www.epa.gov/otaq/gasoline.htm.

54. US EPA, *State Winter Oxygenated Fuel Program Requirements for Attainment or Maintenance of CO NAAQS*. 2008: Washington, D.C.

55. Blue Ribbon Panel on Oxygenates in Gasoline, *Achieving Clean Air and Clean Water: The Report of the Blue Ribbon Panel on Oxygenates in Gasoline*. 1999, U.S. Environmental Protection Agency: Washington, D.C.

56. EPA Office of Mobile Sources. *Is Reformulated Gasoline a "New" Gasoline?* 1995 July 16, 2008 [cited 2009 March 2, 2009]; Available from: http://www.epa.gov/otaq/rfgnew.htm.

57. US EPA. *Origin of the Reformulated Gasoline Program*. 1995 August 14, 2007 [cited 2009 March 2]; Available from: http://www.epa.gov/otaq/rfgorig.htm.

58. US EPA. *Methyl Tertiary Butyl Ether (MTBE)*. 2008 November 24, 2008 [cited 2009 July 19]; Available from: http://www.epa.gov/mtbe/faq.htm.

59. US EPA, *State Action Banning MTBE (Statewide)*. 2007: Washington, D.C.

60. U.S. EPA, *Regulatory Announcement: Removal of Reformulated Gasoline Oxygen Content Requirement*. 2006: Washington, D.C.

61. Energy Information Administration, *Eliminating MTBE in Gasoline in 2006*. 2006, U.S. Department of Energy: Washington, D.C.

62. Green Car Congress. *Nearly All Gasoline in Maine Now E10, Without State Mandate*. 2008 November 1, 2008 [cited 2009 July 20]; Available from: http://www.greencarcongress.com/2008/11/nearly-all-gaso.html.

63. Platts. *MTBE Phase out: A Platts.com news feature*. 2006 March 31, 2006 [cited 2009 July 20]; Available from: http://www.platts.com/Oil/Resources/News%20Features/MTBE/index.xml.

64. Pegg, J.R. *Gas Prices Could Skyrocket When MTBE is Removed*. 2006 March 29, 2006 [cited 2009 July 19]; Available from: http://www.ens-newswire.com/ens/mar2006/2006-03-29-10.asp.

65. Green Car Congress. *Top MTBE Manufacturer Slams EPA Ruling on Oxygenated Fuels*. 2006 March 25, 2006 [cited 2009 July 20, 2009]; Available from: http://www.greencarcongress.com/2006/03/top_mtbe_manufa.html.

66. Lyondell Chemical Company. *Lyondell Urges EPA Action on Gasoline Supply*. 2006 March 24, 2006 [cited 2009 July 21]; Available from: http://lyondellbasell.mediaroom.com/index.php?s=43&item=250.

67. U.S. EIA, *Short-Term Energy Outlook*. 2009, U.S. Department of Energy, Energy Information Administration: Washington, D.C.

68. Urbanchuk, J.M., *Ability of the U.S. Ethanol Industry to Replace MTBE*. 2000, AUS Consultants: Moorestown, NJ.

69. Renewable Fuels Association, *RFA Background Memo: Ethanol Supplies Sufficient To Meet New Demand*. 2006.

70. Dinneen, B., *RFA Letter to EIA Regarding MTBE Elimination*, J. Shore, Editor. 2006, Renewable Fuels Association: Washington, D.C.

71. *Hearing on Gasoline: Supply, Price and Specifications*, in *Energy and Commerce Committee*. 2006, Renewable Fuels Association: Washington, D.C.

72. Renewable Fuels Association. *RFA Press Release: Ethanol Not to Blame For High Gas Prices*. 2006 April 10, 2006 [cited 2009 July 21]; Available from: http://www.ethanolrfa.org/view/?id=629.

73. U.S. EIA, *Short-Term Energy Outlook and Summer Fuels Outlook*. 2006, U.S. Department of Energy, Energy Information Administration: Washington, D.C.

74. U.S. Environmental Protection Agency. *Renewable Fuel Standard Program*. 2008 February 8, 2008 [cited February 8, 2008]; Available from: http://www.epa.gov/otaq/renewablefuels/.

75. US EPA, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements*, Office of Air and Radiation, Editor. 2000: Washington, D.C.

76. Lidderdale, T.C.M., *Demand, Supply, and Price Outlook for Low-Sulfur Diesel Fuel*. 1993, U.S. Department of Energy, Energy Information Administration: Washington, D.C.

77. US EPA, *Regulatory Announcment: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements*. 2000: Washington, D.C.

78. Energy Information Administration. *Sales of Distillate Fuel Oil by End Use*. 2008 December 23, 2008 [cited 2009 July 24]; Available from: http://tonto.eia.doe.gov/dnav/pet/pet_cons_821dst_dcu_nus_a.htm.

79. Energy Information Administration, *The Transition to Ultra-Low-Sulfur Diesel Fuel: Effects on Prices and Supply*. 2001, U.S. Department of Energy, Energy Information Administration: Washington, D.C.

80. Committee on State Practices in Setting Mobile Source Emissions Standards, National Research Council, *State and federal standards for mobile source emissions*. 2006, Washington, DC :: National Academies Press. xxii, 338 p. :.

81. US EPA. *Regulatory Announcment: Direct Final Rule and Notice of Proposed Rulemaking: Revisions to Motor Vehicle Diesel Fuel Sulfur Transition Provisions and Technical Amendments to the Highway Diesel, Nonroad Diesel, and Tier 2 Gasoline Programs*. 2008 July 16, 2008 [cited 2009 July 25]; Available from: http://epa.gov/otaq/regs/fuels/diesel/420f05051.htm.

82. Adebayo, G., *Personal Communication, Impacts of LSD and ULSD on diesel engine fuel system components*, M. O'Donnell, Editor. 2007: Columbus, Indiana.

83. John Deere. *Does John Deere allow the use of Ultra-Low-Sulfur diesel fuel?* 2009 [cited 2009 July 27]; Available from:

http://www.deere.com/en_US/ag/servicesupport/tips/tractors/common_stories/ultra_low_sulfur_diesel_fuel.html#.

84. Jensen, D., *Transition time: New ultra-low-sulfur diesel enters the marketplace*, in *OEM Off-Highway*. 2006, Cyngnus Interactive.

85. Nguyen, T., *U.S. poised for smooth ULSD switch*, in *FleetOwner*. 2006, Penton Media, Inc.

86. National Biodiesel Board, *Lubricity Benefits*. 2002: Jefferson City, MO.

87. USGS, *MIneral Commodity Summaries - Sulfur*. 2001.

88. USGS, *Mineral Commodity Summaries - Sulfur*. 2006.

89. Southeast Farm Press. *Ethanol industry increasing livestock feed supply*. 2008 October 24, 2008 [cited 2009 December 1]; Available from: http://southeastfarmpress.com/biofuels/livestock-feed-1024/.

90. Allen, D.T., et al., *Framework and Guidance for Estimating Greenhouse Gas Footprints of Aviation Fuels (In review, to be published June 2009)*. 2009, U.S. Air Force.

91. Energy Information Administration. *Sulfur*. 2009 June 25, 2009 [cited 2009 July 28]; Available from: http://tonto.eia.doe.gov/dnav/pet/pet_pnp_capprod_a_(na)_8ps_std_a.htm.

92. Sperling, D., *New transportation fuels : a strategic approach to technological change*. 1988, Berkeley: University of California Press. xiv, 532 p.

93. Gold, R. and A. Campoy, *Oil Industry Braces for Drop in U.S. Thirst for Gasoline*, in *The Wall Street Journal*. 2009, Dow Jones & Company, Inc.: New York City.

94. Grubler, A., *The rise and fall of infrastructures: dynamics of evoluation and technological change in transport*. 1990, New York: Springer-Verlag. viii, 305 p.

95. Grubler, A., *Technology and Global Change*. 2003, Cambridge: Cambridge University Press.

96. Marchetti, C. and N. Nakicenovic, *The Dynamics of Energy Systems and the Logistic Substitution Model*. 1979, International Institute for Applied Systems Analysis: Laxenburg, Austria.

97. Kovarik, B. *Charles F. Kettering and the 1921 Discovery of Tetraethyl Lead In the Context of Technological Alternatives*. 1999 [cited 2009 August]; Available from: http://www.runet.edu/~wkovarik/papers/kettering.html.

98. Meinhardt, J., *Kinder Morgan, Central Florida Pipeline batch ship ethanol*, in *Tampa Bay Business Journal*. 2008, Amercian City Business Journals, Inc.: Tampa Bay, Florida.

99. Anonymus, *KMP begins commercial ethanol shipment via pipeline*, in *Tampa Bay Business Journal*. 2008, Amercian City Business Journals, Inc.: Tampa Bay, Florida.

100. Williams, D., *Biofuel pipeline to serve Atlanta*, in *Atlanta Business Chronicle*. 2009, American City Business Journals: Atlanta, Georgia.

101. POET. *POET Joins Magellan Midstream Partners to Assess Dedicated Ethanol Pipeline*. 2009 March 16, 2009 [cited 2009 November 20, 2009]; Available from: http://www.poetenergy.com/news/showRelease.asp?id=155.

102. Greene, D. and A. Schafer, *Reducing Greenhouse Gas Emissions From U.S. Transportation*. 2003, Pew Center on Global Climate Change: Arlington, VA.

103. Committee on Alternatives and Strategies for Future Hydrogen Production and Use, National Research Council, National Academy of Engineering, *The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs*. 2004, Washington, D.C.: The National Academy Press.

104. National Biodiesel Board. *Automakers' and Engine Manufacturers' Positions of Support for Biodiesel Blends*. 2009 [cited 2009 August 14]; Available from: http://www.biodiesel.org/resources/oems/default.aspx.

105. America's Energy Future Panel on Alternative Liquid Transportation Fuels, National Academy of Sciences, National Academy of Engineering, National Research Council, *Liquid Transportation Fuels from Coal and Biomass: Technological Status, Costs, and Environmental Impacts*. 2009, Washington, D.C.: The National Academy Press.

106. Seyferth, D., *The Rise and Fall of Tetraethyllead. 1. Discovery and Slow Development in European Universities, 1853-1920.* Organometallics, 2003. **22**(12): p. 2346-2357.

107. Walker, B., *Internal Industry Documents Are Rewriting The MTBE Pollution Story*. 2002, Environmental Working Group: Washington, D.C.

108. Erdal, S. and B.D. Goldstein, *METHYL tert-BUTYL ETHER AS A GASOLINE OXYGENATE: Lessons for Environmental Public Policy1.* Annual Review of Energy and the Environment, 2000. **25**(1): p. 765-802.

109. Committee on Water Implications of Biofuels Production in the United States, National Research Council, *Water Implications of Biofuels Production in the United States*. 2008, Washington, D.C.: The National Academies Press. 86.

110. Kimbrell, A., *Fatal harvest: the tragedy of industrial agriculture*. 2002, Washington, D.C.: Island Press. xi, 384 p.

111. Twomey, K.M., A.S. Stillwell, and M.E. Webber, *The unintended energy impacts of increased nitrate contamination from biofuels production.* Journal of Environmental Monitoring, 2009.

112. Donner, S.D. and C.J. Kucharik, *Corn-based ethanol production compromises goal of reducing nitrogen export by the Mississippi River*. Proceedings of the National Academy of Sciences, 2008. **105**(11): p. 4513-4518.

113. Lidderdale, T.C.M. *MTBE Production Economics*. 2001 April 5, 2001 [cited 2009 January 28, 2009]; Available from: http://www.eia.doe.gov/emeu/steo/pub/special/mtbecost.html.

114. Davis, J.M. and V.M. Thomas, *Systematic Approach to Evaluating Trade-Offs among Fuel Options*. Annals of the New York Academy of Sciences, 2006. **1076**(Living in a Chemical World: Framing the Future in Light of the Past): p. 498-515.

115. Galbraith, K., *In Gas-Powered World, Ethanol Stirs Complaints*, in *The New York Times*. 2008, The New York Times Company: New York City.

116. Gruebler, A., *Technology and Global Change*. 2003, Cambridge: Cambridge University Press.

117. System Dynamics Society. *What is System Dynamics?* 2008 November 19, 2008 [cited 2008 November 21, 2008]; Available from: http://www.systemdynamics.org/index.html.

118. Sandor, D., R. Wallace, and S. Peterson, *Understanding the Growth of the Cellulosic Ethanol Industry*. 2008, National Renewable Energy Laboratory: Golden, Colorado.

119. Cucinelli, N., et al., *Evolutionary Pathways to Biofuels for Transport*, in *School of Natural Resources and the Environment*. 2005, University of Michigan: Ann Arbor, Michigan.

120. Welch, C., *Lessons Learned from Alternative Transportation Fuels: Modeling Transition Dynamics*. 2006, National Renewable Energy Laboratory: Golden, Colorado.

121. Struben, J., *Identifying Challenges for Sustained Adoption of Alternative Fuel Vehicles and Infrastructure*. 2006, MIT Sloan School of Management: Cambridge, MA.

122. Struben, J. and J. Sterman, *Transition Challenges for Alternative Fuel Vehicle and Transportation Systems*. 2007, MIT Sloan School of Management: Cambridge, MA.

123. Rocha, L. *What are complex systems?* 2003 August 15, 2003 [cited 2008 November 23, 2008]; Available from: http://informatics.indiana.edu/rocha/complex/csm.html.

124. Mahalik, M.R., et al., *Modeling the Transition to Hydrogen-Based Transportation*, in *Proceedings of the Agent 2007 Conference on Complex*

Interaction and Social Emergence, M.J. North, C.M. Macal, and D.L. Sallach, Editors. 2007: Evanston, IL.

125. ANL. *Multi-Agent Simulation of Hydrogen Transition Issues*. 2008 [cited November 4, 2008]; Available from: http://www.dis.anl.gov/news/HydrogenTransitionModeling.html.

126. Schwoon, M., *A tool to optimize the initial distribution of hydrogen filling stations*. Transportation Research Part D: Transport and Environment, 2007. **12**(2): p. 70-82.

127. Lin, Z., et al., *The least-cost hydrogen for Southern California*. International Journal of Hydrogen Energy, 2008. **33**(12): p. 3009-3014.

128. Lin, Z., et al., *The Hydrogen Infrastructure Transition Model (HIT) & Its Application in Optimizing a 50-year Hydrogen Infrastructure for Urban Beijing*. 2006, Institute of Transportation Studies, University of California, Davis: Davis, California.

129. Lin, Z., *HIT model*, M. O'Donnell, Editor. 2008, Oak Ridge National Laboratory: Oak Ridge, Tennessee.

130. Parker, N.C., *Optimizing the Design of Biomass Hydrogen Supply Chains Using Real-World Spatial Distributions: A Case Study Using California Rice Straw*, in *Transportation Technology and Policy*. 2007, University of California, Davis: Davis, California.

131. Parks, K., *Hydrogen Deployment System Modeling Environment (HyDS ME) Documentation*. 2006, National Renewable Energy Laboratory: Golden, Colorado.

132. Brown, E., *Transportation Sector Market Transition: Using History and Geography to Envision Possibly Hydrogen Infrastructure Development and Inform Public Policy*. 2008, National Renewable Energy Laboratory: Golden, Colorado.

133. Lambert, T., *Overview of HyNOON*. 2006, Mistaya Engineering Inc.

134. Leiby, P., et al., *Systems Analysis of Hydrogen Transition with HyTrans*. Transportation Research Record: Journal of the Transportation Research Board, 2006. **1983**(-1): p. 129-139.

135. Greene, D., P. Leiby, and D. Bowman, *Integrated Analysis of Market Transformation Scenarios with HyTrans*. 2007, Oak Ridge National Laboratory: Oak Ridge, Tennessee.

136. Plotkin, S., *Examining Hydrogen Transitions*. 2007, Argonne National Laboratory: Argonne, IL.

137. Leiby, P. and J. Rubin, *Effectiveness and Efficiency of Policies to Promote Alternative Fuel Vehicles.* Transportation Research Record: Journal of the Transportation Research Board, 2001. **1750**(-1): p. 84-91.

138. Leiby, P. and J. Rubin, *Transitions in Light-Duty Vehicle Transportation: Alternative-Fuel and Hybrid Vehicles and Learning.* Transportation Research Record: Journal of the Transportation Research Board, 2003. **1842**(-1): p. 127-134.

139. Greene, D., *TAFV Alternative Fuels and Vehicles Choice Model Documentation*. 2001, Oak Ridge National Laboratory: Oak Ridge, Tennessee.

140. U.S. DOE. *The National Energy Modeling System: An Overview 2003*. 2007 July 24, 2007 [cited 2008 November 16, 2008]; Available from: http://www.eia.doe.gov/oiaf/aeo/overview/.

141. U.S. DOE, *Transportation Sector Module of the National Energy Modeling System: Model Documentation 2007*. 2007, Energy Information Agency, US Department of Energy: Washington, DC.

142. U.S. DOE, *Annual Energy Outlook 2008: With Projections for 2030*. 2008, U.S. Department of Energy, Energy Information Administration.

143. U.S. EPA. *MARKAL Technology Database and Model (EPANMD)*. 2007 January 10, 2007 [cited 2008 November 23, 2008]; Available from: http://www.epa.gov/appcdwww/apb/globalchange/markal.htm.

144. POLYSYS. *POLYSYS - Policy Analysis System*. 2008 [cited 2008 November 22, 2008]; Available from: http://www.agpolicy.org/polysys.html.

145. De La Torre Ugarte, D.G., et al., *The Economic Impacts of Bioenergy Crop Production on U.S. Agriculture*. 2003, United States Department of Agriculture.

146. Smil, V., *Energy at the Crossroads*. 2003, Cambridge: The MIT Press. 427.

147. ASPO-USA, *Long Range Forecasting & Oil Prices: Energy Information Administration Critique*. 2008, Energy Literacy Advocates: Fort Collins, Colorado.

148. Wallace, B., *2005 OBP Biennial Peer Review, Platform Analysis Overview: Integrated Biorefinery Project*. 2005.

149. Trenberth, K.E., et al., *Common questions about climate change*. 1997, United Nations Environment Programme (UNEP), World Meteorological Organization (WMO): Nairobi.

150. USDA. *Background Statistics: U.S. Citrus Market*. 2007 January 22, 2007 [cited 2008 November 23, 2008]; Available from: http://www.ers.usda.gov/News/citruscoverage.htm.

151. Levene, J., *Hydrogen Demand and Resource Analysis (HyDRA) Project*, in *SEAAC Seminar Series*. 2008, National Renewable Energy Laboratory.

152. Melendez, M. and A. Milbrandt, *Geographically Based Hydrogen Consumer Demand and Infrastructure Analysis*. 2006, National Renewable Energy Laboratory: Golden, Colorado.

153. Milbrandt, A. and M. Mann, *Potential for Hydrogen Production from Key Renewable Resources in the United States*. 2007, National Renewable Energy Laboratory: Golden, Colorado.

154. Ni, J., et al., *Estimating Hydrogen Demand Distribution Using Geographic Information Systems (GIS)*, in *National Hydrogen Association (NHA) Annual Hydrogen Conference*. 2005: Washington, DC.

155. Yang, C., M. Nicholas, and J. Ogden, *Technical and Economic Assessment of Regional Hydrogen Transition Strategies*. 2007, Institute of Transportation Studies, University of California, Davis: Davis, California.

156. Energy Information Administration. *The National Energy Modeling System: An Overview 2003*. 2007 July 24, 2007 [cited 2008 November 16, 2008]; Available from: http://www.eia.doe.gov/oiaf/aeo/overview/.

157. Farrell, A.E. and D. Sperling, *A Low-Carbon Fuel Standard for California, Part 1: Technical Analysis*. 2007.

158. Energy Information Administration, *Updated AEO2009 Reference Case Service Report*. 2009, U.S. Department of Energy, Energy Information Administration: Washington, D.C.

159. Energy Information Administration, *Annual Energy Outlook 2009 with Projections to 2030, Updated Annual Energy Outlook 2009 Reference Case with ARRA, Table 11. Liquid Fuels Supply and Disposition*. 2009, U.S. Department of Energy, Energy Information Administration: Washington, D.C.

160. US EPA, *Waiver Requests Under Section 211(f) of the Clean Air Act*. 1995: Washington, D.C.

161. ASTM International News Releases. *New Biodiesel Specifications Published by ASTM International*. 2008 October, 2008 [cited 2009 August 14]; Available from: http://astmnewsroom.org/default.aspx?pageid=1515.

162. Energy Information Administration, *Annual Energy Outlook 2009, Appendix E: NEMS Overview and Brief Description of Cases*. 2009, U.S. Department of Energy, Energy Information Administration: Washington, D.C.

163. Office of the Press Secretary. *President Obama Announces National Fuel Efficiency Policy*. 2009 May 19, 2009 [cited 2009 August 27]; Available from: http://www.whitehouse.gov/the_press_office/President-Obama-Announces-National-Fuel-Efficiency-Policy/.

164. Johnson, S., *Cash for Clunkers Payout Nearly Complete*. 2009, U.S. Department of Transportation, Office of Public Affairs: Washington, D.C.

165. NHTSA. *CARS: car allowance rebate system*. 2009 November 3, 2009 [cited 2009 November 3, 2009]; Available from: http://www.cars.gov/.

166. Acerra, M., *Threats and opportunities for the European refining industry*. 2008, Gerson Lehrman Group.

167. Wang, M., *The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model*. 2009, U.S. Department of Energy, Argonne National Laboratory.

168. Knoll, K., et al., *Effects of Intermediate Ethanol Blends on Legacy Vehicles and Small Non-Road Engines, Report 1 - Updated*. 2009, Oak Ridge National Laboratory.

169. Christie, M. and J. Stokes, *Optimized flex fuel powertrain*, in *Patent Storm*, U.S. Patent Office, Editor. 2008, Ricardo, Inc.: United States.

170. Agarwal, A. and P. Whitaker, *E85 Optimized Engine*. 2009, Ford Motor Company, AVL Powertrain Engineering Inc.

171. Ruggiero, J. *DOE to Provide up to $21.5 million for Research to Improve Vehicle Efficiency*. 2007 August 7, 2007 [cited 2009 August 14]; Available from: http://www.energy.gov/news/5298.htm.

172. International Sustainable Energy Exchange (ISEE). *Renewable Fuels*. 2009 August 14, 2009 [cited 2009 August 14]; Available from: http://www.hart-isee.com/index.php?page=alternative-fuels.

173. Energy Information Administration, *Annual Energy Outlook 2009*. 2009, U.S. Department of Energy, Energy Information Administration: Washington, D.C.

174. US EPA, *1991 Interpretive Rule for the term "Substantially Similar"*, Office of Transportation and Air Quality, Editor. 1991: Washington, D.C.

175. US EPA, *Notice of Receipt of a Clean Air Act Waiver Application To Increase the Alllowable Ethanol Content of Gasoline to 15 Percent; Reqest for Comment*, Environmental Protection Agency (EPA), Editor. 2009, Federal Register: Washington, D.C. p. 18228-18230.

176. Reardon, M. and W. Silcock. *Biobutanol Performance Similar to Unleaded Gasoline, According to New Fuel Testing*. 2007 April 19, 2007 [cited 2009 November 12]; Available from: http://onlinepressroom.net/DuPont/NewsReleases/.

177. Dupont. *Biofuels: Biobutanol*. 2009 [cited 2009 August 26]; Available from: http://www2.dupont.com/Renewably_Sourced_Materials/en_US/biobutanol.html.

178. Childs, D. *DuPont and BP building biobutanol facility in U.K.* 2007 June 27, 2007 [cited 2009 November 12]; Available from: http://cleantech.com/news/1383/dupont-and-bp-building-biobutanol-faci.

179. Trompiz, G. *BP eyes output of new biofuels from next year*. 2009 November 3, 2009 [cited 2009 November 12]; Available from: http://www.reuters.com/article/marketsNews/idUSL367896420091103.

180. Voegele, E., *The Push for E15*, in *Ethanol Producer Magazine*. 2009, BBI International Media: Grand Forks, ND.

181. Krauss, C., *Valero Energy, the Oil Refiner, Wins an Auction for 7 Ethanol Plants*, in *The New York Times*. 2009, The New York Times Company: New York City.

182. Krauss, C., *Big Oil Warms to Ethanol and Biofuel Companies*, in *The New York Times*. 2009, The New York Times Company: New York City.

183. Business Wire. *ExxonMobil to Launch Biofuels Program*. 2009 July 14, 2009 [cited 2009 November 23]; Available from: http://www.businesswire.com/portal/site/exxonmobil/?ndmViewId=news_view&newsId=20090714005554&newsLang=en.

184. ExxonMobil. *Algae biofuels*. 2009 [cited 2009 November 24]; Available from: http://www.exxonmobil.com/Corporate/energy_climate_con_vehicle_algae.aspx.

185. Aden, A., et al., *Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis for Corn Stover*. 2002, National Renewable Energy Laboratory, U.S. Department of Energy: Golden, CO.

186. De La Torre Ugarte, D.G. and D.E. Ray, *Biomass and bioenergy applications of the POLYSYS modeling framework.* Biomass and Bioenergy, 2000. **18**(4): p. 291-308.

187. Hammerschlag, R., *Ethanol's Energy Return on Investment: A Survey of the Literature 1990-Present.* Environ. Sci. Technol., 2006. **40**(6): p. 1744-1750.

188. Perlack, R.D., et al., *Biomass as Feedstock for a Bioenergy and Bioproducts Industry: The Technical Feasibility of a Billion-Ton Annual Supply*. 2005, Oak Ridge National Laboratory, US Department of Energy.

189. Pimentel, D. and T.W. Patzek, *Ethanol Production Using Corn, Switchgrass, and Wood; Biodiesel Production Using Soybean And Sunflower.* Natural Resources Research, 2005. **14**(1): p. 65-76.

190. Schmer, M.R., et al., *Net energy of cellulosic ethanol from switchgrass.* Proceedings of the National Academy of Sciences, 2008. **105**(2): p. 464-469.

191. Solomon, B.D., J.R. Barnes, and K.E. Halvorsen, *Grain and cellulosic ethanol: History, economics, and energy policy.* Biomass and Bioenergy, 2007. **31**(6): p. 416-425.

192. The Royal Society, *Sustainable biofuels: prospects and challenges*. 2008, London: The Royal Society.

193. National Commission on Energy Policy, *Task Force on Biofuels Infrastructure*. 2008, National Commission on Energy Policy, Bipartisan Policy Center: Washington, D.C.

194. Renewable Fuels Association. *Statistics*. 2009 [cited 2009 November 23, 2009]; Available from: http://www.ethanolrfa.org/industry/statistics/.

195. Gardner, K.W., *U.S. Gasoline Requirements*. 2007, ExxonMobil.

196. Peterson, B., S.-M. Chin, and S. Das, *Analysis of Fuel Ethanol Transportation Acitivity and Potential Distribution Constraints*. 2009, Oak Ridge National Laboratory, U.S. Department of Energy: Oak Ridge, TN.

197. Downstream Alternatives Inc., *Infrastructure Requirements for an Expanded Fuel Ethanol Industry*. 2002: South Bend, IN.

198. Pentland, W. *Ethanol: Getting There Is None Of The Fun*. 2008 May 16, 2008 [cited 2009 November 23]; Available from: http://www.forbes.com/2008/05/15/ethanol-logistics-energy-biz-logistics-cx_wp_0516ethanol.html.

199. Sridhar, N., *Transportation of Biofuel Through Pipelines*. 2008, Det Norske Veritas AS.

200. AOPL/API, *Ethanol and Pipeline Transportation Policy Paper*. 2007, Association of Oil Pipe Lines and American Petroleum Institute.

201. Mahon, J. *Kinder Morgan Presentation*. in *Next Generation Biofuels - Trends in Global Innovation and Finance: The Tools of Biotechnology Meet the World's Energy Challenge*. 2007. Houston, Texas.

202. Energetics Incorporated, *Safe & Reliable Ethanol Transportation & Storage Technology Roadmapping Workshop: Workshop Summary Results*. 2007, CC Technologies: Dublin, Ohio.

203. Magellan Midstream Partners, POET, ESRI, *Preliminary Pipeline Route*. 2009, Magellan Midstream Partners, LP: Tulsa, OK.

204. National Renewable Energy Laboratory, *Cost of Adding E85 Fueling Capability to Existing Gasoline Stations: NREL Survey and Literature Search*. 2008, National Renewable Energy Laboratory: Golden, Colorado.

205. E85Prices.com. *E85Prices.com: The first and only site dedicated to covering the price of E85*. 2009 [cited 2009 November 23]; Available from: http://e85prices.com/.

206. Joseph Jr., H., *The Vehicle Adaptation to Ethanol Fuel*, in *Royal Society Multilateral Second Generation Biofuels Event*. 2007: The Royal Society, London, UK.

207. DiCicco, D., *An Auto Industry Perspective on the Ethanol Blendwall*, in *Mobile Source Technical Review Subcommittee*. 2009, Ford: Washington, D.C.

208. Lu, S., *Vehicle Survivability and Travel Mileage Schedules*. 2006, National Center for Statistics and Analysis, Regulatory Analysis and Evaluation Division, National Highway Traffic Safety Administration, U.S. Department of Transportation: Washington, D.C.

209. Energy Information Administration, *Alternatives to Traditional Transportation Fuels 2007*. 2009, U.S. Department of Energy: Washington, D.C.

210. Energy Information Administration, *Annual Energy Outlook 2009 with Projections to 2030, Updated Annual Energy Outlook 2009 Reference Case with ARRA, Table 58. Light-Duty Vehicle Stock by Technology Type*. 2009, U.S. Department of Energy, Energy Information Administration: Washington, D.C.

211. Davis, S.C., S.W. Diegel, and R.G. Boundy, *Transportation Energy Data Book*. 2009, Oak Ridge National Laboratory,: Oak Ridge, Tennessee.

212. Jensen, C., *Ethanol Industry's 15% Solution Raises Concerns*, in *The New York Times*. 2009, The New York Times Company: New York City.

213. Hughes, S. and L. Etter, *EPA Considers Higher Ethanol Mix*, in *The Wall Street Journal*. 2009, Dow Jones & Company, Inc.: New York City.

214. Jensen, C., *Laboratory Will Not Certify Pumps for Gas With 15 Percent Ethanol*, in *The New York Times*. 2009, The New York Times Company: New York City.

215. (UL), U.L. *UL announces new certification path for ethanol fuel dispensers*. 2009 August 10, 2009 [cited 2009 November 27]; Available from: http://www.ul.com/global/eng/pages/corporate/newsroom/newsitem.jsp?n=ul-announces-new-certification-path-for-ethanol-fuel_20090810122400.

216. Brekke, K. *Unprecedented National Campaign to Expand Renewable Fuel Infrastructure Begins*. 2009 August 11, 2009 [cited 2009 November 27]; Available from: http://www.ethanol.org/pdf/contentmgmt/BYOethanol_final_press_release_8112009.pdf.

217. NACS Online. *Ethanol Industry Launches Blender Pump Campaign*. 2009 August 14, 2009 [cited 2009 November 27]; Available from: http://www.nacsonline.com/NACS/News/Daily/Pages/ND0814092.aspx.

218. Platform, E.B.T. *Biomass to Liquids (BtL)*. 2009 October 21, 2009 [cited 2009 November 27]; Available from: http://www.biofuelstp.eu/btl.html.

219. Wogan, D., et al., *Algae: Pond Powered Biofuels*. 2008, Clean Energy Incubator, The University of Texas at Austin: Austin, Texas.

220. Rabinow, R.A., *The Liquid Pipeline Industry in the United States: Where It's Been, Where It's Going*. 2004, Association of Oil Pipe Lines (AOPL).

221. Sperling, D., *Brazil, Ethanol, and the Process of System Change.* Energy, 1987. **12**(1): p. 11-23.

222. Goodman, B., *Pollution is Called a Byproduct of a 'Clean' Fuel*, in *The New York Times*. 2008, The New York Times Company: New York City.

223. Fargione, J., et al., *Land Clearing and the Biofuel Carbon Debt.* Science, 2008. **319**: p. 1235-1238.

224. Searchinger, T., et al., *Use of U.S. Croplands for Biofuels Increases Greenhouse Gases Through Emissions from Land Use Change.* Science, 2008. **319**: p. 1238-1240.

Vita

Michael Joseph O'Donnell, the son of David R. and Jeanne M. O'Donnell, was born in Cork, Ireland on October 27, 1981. In 1999, he graduated as valedictorian from William Henry Harrison High School in West Lafayette, Indiana. That same year, he began his undergraduate studies at Purdue University in West Lafayette, Indiana. He was awarded the degree of Bachelor of Science in Mechanical Engineering (with Highest Distinction) in 2004. While studying at Purdue University, he also completed the University-Industry Cooperative Education Program in Engineering with GE Aircraft Engines in Cincinnati, Ohio. After completing his undergraduate degree, he was employed as an engineer at Cummins Inc., in Columbus, Indiana. In August, 2007, he entered the Graduate School at the University of Texas at Austin in the Department of Mechanical Engineering.

Email address: mjosjo@gmail.com

This thesis was typed by the author.